Nick Wintermantel | Principal, Astrapé Consulting, LLC

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Mr. Wintermantel has 20 years of experience in utility planning and electric market modeling. Areas of utility planning experience includes utility integrated resource planning (IRP) for vertically-integrated utilities, market price forecasting, resource adequacy modeling, RFP evaluations, environmental compliance analysis, asset management, financial risk analysis, and contract structuring. Mr. Wintermantel also has expertise in production cost simulations and evaluation methodologies used for IRPs and reliability planning. As a consultant with Astrapé Consulting, Mr. Wintermantel has managed reliability and planning studies for large power systems across the U.S. and internationally. Prior to joining Astrapé Consulting, Mr. Wintermantel was employed by the Southern Company where he served in various resource planning, asset management, and generation development roles.

Experience

Principal Consultant at Astrapé Consulting (2009 – Present)

Managed detailed system resource adequacy studies for large scale utilities
Managed ancillary service and renewable integration studies
Managed capacity value studies
Managed resource selection studies
Performed financial and risk analysis for utilities, developers, and manufacturers
Demand side resource evaluation
Storage evaluation
Served on IE Teams to evaluate assumptions, models, and methodologies for competitive procurement solicitations
Project Management on large scale consulting engagements
Production cost model development
Model quality assurance
Sales and customer service

Sr. Engineer for Southern Company Services (2007-2009)

Integrated Resource Planning and environmental compliance
Developed future retail projects for operating companies while at the Southern Company
Asset management for Southern Company Services

Sr. Engineer for Southern Power Company (Subsidiary of Southern Company) (2003-2007)

Structured wholesale power contracts for Combined Cycle, Coal, Simple Cycle, and IGCC Projects
Model development to forecast market prices across the eastern interconnect
Evaluate financials of new generation projects
Bid development for Resource Solicitations

Cooperative Student Engineer for Southern Nuclear (2000-2003)

Probabilistic risk assessment of the Southern Company Nuclear Fleet

ASTRAPÉ CONSULTING
innovation in electric system planning

Industry Specialization

Resource Adequacy Planning	Resource Planning	Integrated Resource Planning
Competitive Procurement	Asset Evaluation	Financial Analysis
Environmental Compliance Analysis	Generation Development	Capacity Value Analysis
Renewable Integration	Ancillary Service Studies	

Education

MBA, University of Alabama at Birmingham – Summa Cum Laude
B.S. Degree Mechanical Engineering - University of Alabama - Summa Cum Laude

Relevant Experience

Resource Adequacy Planning and Production Cost Modeling

Tennessee Valley Authority: Performed Various Reliability Planning Studies including Optimal Reserve Margin Analysis, Capacity Benefit Margin Analysis, and Demand Side Resource Evaluations using the Strategic Energy and Risk Valuation Model (SERVM) which is Astrapé Consulting's proprietary reliability planning software. Recommended a new planning target reserve margin for the TVA system and assisted in structuring new demand side option programs in 2010. Performed Production Cost and Resource Adequacy Studies in 2009, 2011, 2013, 2015 and 2017. Performed renewable integration and ancillary service work from 2015-2017.

Southern Company Services: Assisted in resource adequacy and capacity value studies as well as model development from 2009 – 2018.

Louisville Gas & Electric and Kentucky Utilities: Performed reliability studies including reserve margin analysis for its Integrated Resource Planning process. Ongoing support for Resource Adequacy from 2011 – 2020.

Duke Energy: Performed resource adequacy studies for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC in 2012 and 2016. Performed capacity value and ancillary service studies in 2018. Performed Resource Adequacy and Battery ELCC Study in 2020.

California Energy Systems for the 21st Century Project: Performed 2016 Flexibility Metrics and Standards Project. Developed new flexibility metrics such as EUE_{flex} and $LOLE_{flex}$ which represent LOLE occurring due to system flexibility constraints and not capacity constraints.

Terna: Performed Resource Adequacy Study used to set demand curves in Italian Capacity Market Design.

Pacific Gas and Electric (PG&E): Performed flexibility requirement and ancillary service study from 2015–2017. Performed CES Study for Renewable Integration and Flexibility from 2015 – 2016.

PNM (Public Service Company of New Mexico): Managed resource adequacy studies, renewable integration studies and ancillary service studies from 2013 – 2020. Performed resource selection studies in 2017 and 2018. Evaluated storage.

GASOC: Managed resource adequacy studies from 2015 – 2018.

MISO: Managed resource adequacy study and provided support from 2015 – 2020.

SPP: Managed resource adequacy study in 2017 and provided ongoing support through 2020. Performed a Storage ELCC Study in 2019.

Malaysia (TNB, Sabah, Sarawak)): Performed and managed resource adequacy studies from 2015-2018 for three different Malaysian entities.

ERCOT: Performed economic optimal reserve margin studies in cooperation with the Brattle Group in 2014 and 2018. The report examined total system costs, generator energy margins, reliability metrics, and economics under various market structures (energy only vs. capacity markets). Completed a Reserve Margin Study requested by the PUCT, examining an array of physical reliability metrics in 2014 (See Publications: Expected Unserved Energy and Reserve Margin Implications of Various Reliability Standards). Probabilistic Risk Assessment for the North American Electric Reliability Corporation (NERC) in 2014, 2016, and 2018.

FERC: Performed economics of resource adequacy work in 2012-2013 in cooperation with the Brattle Group. Work included analyzing resource adequacy from regulated utility and structured market perspective.

EPRI: Performed research projects studying reliability impact and flexibility requirements needed with increased penetration of intermittent resources in 2013. Created Risk-Based Planning system reliability metrics framework in 2014 that is still in use today.

California Public Utilities Commission: Provided ongoing support for Resource Adequacy work.

Duke Energy Carolinas

2020 Resource Adequacy Study

9/1/2020

PREPARED FOR

Duke Energy

PREPARED BY

Kevin Carden
Nick Wintermantel
Cole Benson
Astrapé Consulting

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Executive Summary

This study was performed by Astrapé Consulting at the request of Duke Energy Carolinas (DEC) as an update to the study performed in 2016. The primary purpose of this study is to provide Duke system planners with information on physical reliability and costs that could be expected with various reserve margin[1] planning targets. Physical reliability refers to the frequency of firm load shed events and is calculated using Loss of Load Expectation (LOLE). The one day in 10-year standard (LOLE of 0.1) is interpreted as one day with one or more hours of firm load shed every 10 years due to a shortage of generating capacity and is used across the industry[2] to set minimum target reserve margin levels. Astrapé determined the reserve margin required to meet the one day in 10-year standard for the Base Case and multiple sensitivities included in the study. The study includes a Confidential Appendix containing confidential information such as fuel costs, outage rate data and transmission assumptions.

Customers expect to have electricity during all times of the year but especially during extreme weather conditions such as cold winter days when resource adequacy[3] is at risk for DEC[4]. In order

[1] Throughout this report, winter and summer reserve margins are defined by the formula: (installed capacity - peak load) / peak load. Installed capacity includes capacity value for intermittent resources such as solar and energy limited resources such as battery.

[2] https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf; See Table 14 in A-1. PJM, MISO, NYISO ISO-NE, Quebec, IESO, FRCC, APS, NV Energy all use the 1 day in 10 year standard. As of this report, it is Astrapé's understanding that Southern Company has shifted to the greater of the economic reserve margin or the 1 day in 10 year standard.

[3] NERC RAPA Definition of "Adequacy" - The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf, at 9.

[4] Section (b)(4)(iv) of NCUC Rule R8-61 (Certificate of Public Convenience and Necessity for Construction of Electric Generation Facilities) requires the utility to provide "… a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area using information from the National Weather Service Automated Surface Observing System (ASOS) First Order Station in Asheville, Charlotte, Greensboro, Hatteras, Raleigh or Wilmington, depending upon the station that is located closest to where the plant will be located."

to ensure reliability during these peak periods, DEC maintains a minimum reserve margin level to manage unexpected conditions including extreme weather, load growth, and significant forced outages. To understand this risk, a wide distribution of possible scenarios must be simulated at a range of reserve margins. To calculate physical reliability and customer costs for the DEC system, Astrapé Consulting utilized a reliability model called SERVM (Strategic Energy and Risk Valuation Model) to perform thousands of hourly simulations for the 2024 study year at various reserve margin levels. Each of the yearly simulations was developed through a combination of deterministic and stochastic modeling of the uncertainty of weather, economic growth, unit availability, and neighbor assistance.

In the 2016 study, reliability risk was concentrated in the winter and the study determined that a 16.5% reserve margin was required to meet the one day in 10-year standard (LOLE of 0.1), for DEC. Because DEC's sister utility DEP required a 17.5% reserve margin to meet the same reliability standard, Duke Energy averaged the studies and used a 17% planning reserve margin target for both companies in its Integrated Resource Plan (IRP). This 2020 Study updates all input assumptions to reassess resource adequacy. As part of the update, several stakeholder meetings occurred to discuss inputs, methodology, and results. These stakeholder meetings included representatives from the North Carolina Public Staff, the South Carolina Office of Regulatory Staff (ORS), and the North Carolina Attorney General's Office. Following the initial meeting with stakeholders on February 21, 2020, the parties agreed to the key assumptions and sensitivities listed in Appendix A, Table A.1.

Preliminary results were presented to the stakeholders on May 8, 2020 and additional follow up was done throughout the month of May. Moving from the 2016 Study, the Study Year was shifted from 2019 to 2024 and assumed solar capacity was updated to the most recent projections. Because solar projections increased, LOLE has continued to shift from the summer to the winter. The high volatility in peak winter loads seen in the 2016 Study remained evident in recent historical data. In response to stakeholder feedback, the four year ahead economic load forecast error was dampened by providing a higher probability weighting on over-forecasting scenarios relative to under-forecasting scenarios. The net effect of the new distribution is to slightly reduce the target reserve margin compared to the previous distribution supplying slight upward pressure on the target reserve margin. This means that if the target reserve margin from this study is adopted, no reserves would be held for potential under-forecast of load growth. Generator outages remained in line with 2016 expectations, but additional cold weather outages of 260 MW for DEC were included for temperatures less than 10 degrees.

Physical Reliability Results-Island

Table ES1 shows the monthly contribution of LOLE at various reserve margin levels for the Island scenario. In this scenario, it is assumed that DEC is responsible for its own load and that there is no assistance from neighboring utilities. The summer and winter reserve margins differ for all scenarios due to seasonal demand forecast differences, weather-related thermal generation capacity differences, demand response seasonal availability, and seasonal solar capacity value. Using the one day in 10-year standard (LOLE of 0.1), which is used across the industry to set minimum target reserve margin levels, DEC would require a 22.5% winter reserve margin in the Island Case where no assistance from neighboring systems was assumed.

Given the significant level of solar on the system, the summer reserves are approximately 2% greater than winter reserves which results in essentially no reliability risk in the summer months when total LOLE is 0.1 days per year. This 22.5% reserve margin is required to cover the combined risks seen in load uncertainty, weather uncertainty, and generator performance for the DEC system. As discussed below, when compared to Base Case results which recognizes neighbor assistance, results of the Island Case illustrate both the benefits and risks of carrying lower reserve margins through reliance on neighboring systems.

Table ES1. Island Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
10.0%	12.4%	0.81	0.14	0.08	-	0.00	0.12	0.70	0.80	0.31	0.11	0.02	0.27	2.05	1.31	3.36
11.0%	13.3%	0.69	0.12	0.06	-	0.00	0.09	0.48	0.51	0.19	0.07	0.01	0.20	1.35	1.09	2.44
12.0%	14.2%	0.58	0.10	0.05	-	0.00	0.06	0.31	0.33	0.12	0.04	0.01	0.15	0.87	0.88	1.75
13.0%	15.0%	0.48	0.08	0.04	-	0.00	0.04	0.19	0.21	0.07	0.03	0.00	0.11	0.55	0.71	1.26
14.0%	15.9%	0.40	0.07	0.03	-	0.00	0.02	0.11	0.14	0.04	0.02	0.00	0.08	0.34	0.58	0.92
15.0%	16.8%	0.33	0.06	0.03	-	-	0.02	0.07	0.09	0.03	0.01	-	0.06	0.21	0.47	0.68
16.0%	17.6%	0.28	0.05	0.02	-	-	0.01	0.04	0.05	0.02	0.01	-	0.04	0.13	0.39	0.52
17.0%	18.5%	0.23	0.04	0.02	-	-	0.01	0.03	0.03	0.01	0.00	-	0.03	0.09	0.32	0.41
18.0%	19.4%	0.19	0.03	0.01	-	-	0.01	0.02	0.02	0.01	0.00	-	0.03	0.06	0.27	0.33
19.0%	20.2%	0.16	0.03	0.01	-	-	0.01	0.02	0.01	0.00	-	-	0.02	0.04	0.22	0.26
20.0%	21.1%	0.13	0.02	0.01	-	-	0.00	0.01	0.01	0.00	-	-	0.02	0.02	0.18	0.20
21.0%	22.0%	0.11	0.02	0.00	-	-	0.00	0.00	0.01	0.00	-	-	0.01	0.01	0.14	0.15
22.0%	22.8%	0.08	0.01	0.00	-	-	0.00	0.00	0.01	0.00	-	-	0.01	0.01	0.10	0.11
23.0%	23.7%	0.06	0.01	0.00	-	-	0.00	0.00	0.00	0.00	-	-	0.00	0.00	0.08	0.08
24.0%	24.6%	0.05	0.01	0.00	-	-	0.00	0.00	0.00	0.00	-	-	0.00	0.00	0.06	0.06

Physical Reliability Results-Base Case

Astrapé recognizes that DEC is part of the larger eastern interconnection and models neighbors one tie away to allow for market assistance during peak load periods. However, it is important to also understand that there is risk in relying on neighboring capacity that is less dependable than owned or contracted generation in which DEC would have first call rights. While there are certainly advantages of being interconnected due to weather diversity and generator outage diversity across regions, market assistance is not guaranteed and Astrapé believes Duke Energy has taken a moderate to aggressive approach (i.e. taking significant credit for neighboring regions) to modeling neighboring assistance compared to other surrounding entities such as PJM Interconnection L.L.C. (PJM)[5] and the Midcontinent Independent System Operator (MISO)[6]. A full description of the market assistance modeling and topology is available in the body of the report. Table ES2 shows the monthly LOLE at various reserve margin levels for the Base Case scenario which is the Island scenario with neighbor assistance included.[7]

[5] PJM limits market assistance to 3,500 MW which represents approximately 2.3% of its reserve margin compared to 6.5% assumed for DEC. https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20191008/20191008-pjm-reserve-requirement-study-draft-2019.ashx – page 11
[6] MISO limits external assistance to a Unforced Capacity (UCAP) of 2,331 MW which represents approximately 1.8% of its reserve margin compared to 6.5% assumed for DEC. https://www.misoenergy.org/api/documents/getbymediaid/80578 page 24 (copy and paste link in browser)
[7] Reference Appendix B, Table B.1 for percentage of loss of load by month and hour of day for the Base Case.

Table ES2. Base Case Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
5.00%	8.11%	0.21	0.05	0.02	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.04	0.05	0.33	0.38
6.00%	8.97%	0.20	0.05	0.02	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.04	0.04	0.30	0.35
7.00%	9.84%	0.18	0.05	0.02	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.03	0.04	0.28	0.31
8.00%	10.71%	0.17	0.04	0.01	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.03	0.03	0.25	0.28
9.00%	11.57%	0.15	0.04	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.03	0.03	0.23	0.25
10.00%	12.44%	0.14	0.04	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.02	0.21	0.23
11.00%	13.31%	0.13	0.03	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.02	0.18	0.20
12.00%	14.18%	0.11	0.03	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.16	0.18
13.00%	15.04%	0.10	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.15	0.15
14.00%	15.91%	0.09	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.13	0.13
15.00%	16.78%	0.08	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.11	0.12
16.00%	17.64%	0.07	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.10	0.10
17.00%	18.51%	0.06	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08
18.00%	19.38%	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.07
19.00%	20.24%	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.06
20.00%	21.11%	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.05
21.00%	21.98%	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.04
22.00%	22.84%	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00-	0.03	0.03

As the table indicates, the required reserve margin to meet the one day in 10-year standard (LOLE of 0.1), is 16.00% which is 6.50% lower than the required reserve margin for 0.1 LOLE in the Island scenario. Approximately one third of the 22.5% required reserves is reduced due to interconnection ties. Astrapé also notes utilities around the country are continuing to retire and replace fossil-fuel resources with more intermittent or energy limited resources such as solar, wind, and battery capacity. For example, Dominion Energy Virginia has made substantial changes to its plans as this study was being conducted and plans to add substantial solar and other renewables to its system that could cause additional winter reliability stress than what is modeled. The below excerpt is from page 6 of Dominion Energy Virginia's 2020 IRP[8]:

> In the long term, based on current technology, other challenges will arise from the significant development of intermittent solar resources in all Alternative Plans. For example, based on the nature of solar resources, the Company will have excess capacity in the summer, but not enough capacity in the winter. Based on current technology, the Company would need to meet this winter deficit by either building additional energy storage resources or by buying capacity from the market. In addition, the Company would likely need to import a significant amount of energy during the winter, but would need to export or store significant amounts of energy during the spring and fall.

Additionally, PJM now considers the DOM Zone to be a winter peaking zone where winter peaks are projected to exceed summer peaks for the forecast period.[9] While this is only one example, these potential changes to surrounding resource mixes may lead to less confidence in market assistance for the future during early morning winter peak loads. Changes in neighboring system resource portfolios and load profiles will be an important consideration in future resource adequacy studies. To the extent historic diversification between DEC and neighboring systems declines, the historic reliability benefits DEC has experienced from being an interconnected system will also decline. It is worth nothing that after this study was completed, California experienced rolling blackouts during extreme weather conditions as the ability to rely on imported power has declined and has shifted away from dispatchable fossil-fuel resources and put greater reliance on intermittent resources.[10] It is premature to fully ascertain the lessons learned from the California load shed events. However, it does highlight the fact that as DEC reduces dependence on

[8] https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509
[9] Dominion Energy Virginia 2020 IRP, at 40.
[10] http://www.caiso.com/Documents/ISO-Stage-3-Emergency-Declaration-Lifted-Power-Restored-Statewide.pdf

dispatchable fossil fuels and increases dependence on intermittent resources, it is important to ensure it is done in a manner that does not impact reliability to customers.

Physical Reliability Results-DEC/DEP Combined Case

In addition to running the Island and Base Case scenarios, a DEC and DEP Combined Case scenario was simulated to see the reliability impact of DEC and DEP as a single balancing authority. In this scenario, DEC and DEP prioritize helping each other over their other external neighbors but also retain access to external market assistance. The various reserve margin levels are calculated as the total resources in both DEC and DEP using the combined coincident peak load, and reserve margins are increased together for the combined utilities. Table ES3 shows the results of the Combined Case which shows that a 16.75% combined reserve margin is needed to meet the 1 day in 10-year standard. An additional Combined Case sensitivity was simulated to assess the impact of a more constrained import limit. This scenario assumed a maximum import limit from external regions into the sister utilities of 1,500 MW[11] resulting in an increase in the reserve margin from 16.75% to 18.0%.

Table ES3. Combined Case Physical Reliability Results

Sensitivity	1 in 10 LOLE Reserve Margin
Base Case	16.0%
Combined Target	16.75%
Combined Target 1,500 MW Import Limit	18.00%

[11] 1,500 MW represents approximately 4.7% of the total reserve margin requirement which is still less constrained than the PJM and MISO assumptions noted earlier.

Results for the Combined Case and the individual Base Cases are outlined in the table below. The DEP results are documented in a separate report but show that a 19.25% reserve margin is required to meet the one day in 10-year standard (LOLE of 0.1).

Table ES4. Combined Case Differences

Region	1 in 10 LOLE Reserve Margin
DEC	16.00%
DEP	19.25%
Combined (Coincident)	16.75%

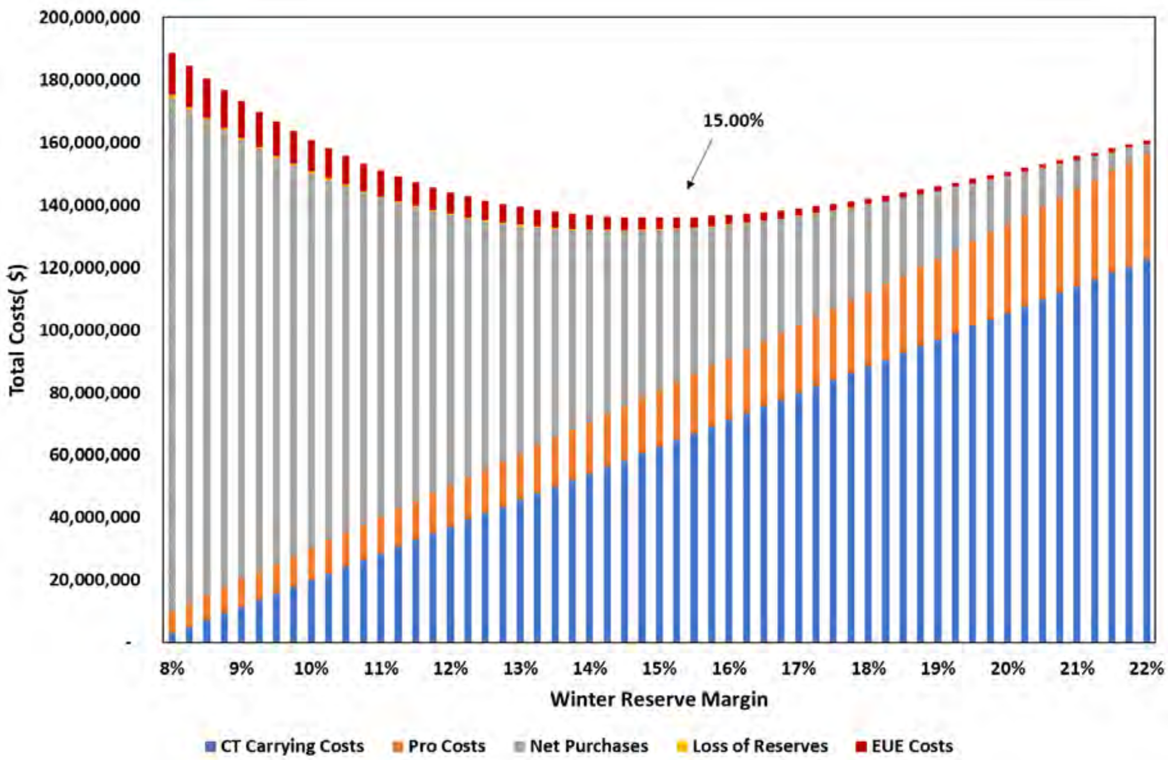
Economic Reliability Results

While Astrapé believes physical reliability metrics should be used for determining planning reserve margin because customers expect to have power during extreme weather conditions, customer costs provide additional information in resource adequacy studies. From a customer cost perspective, total system costs[12] were analyzed across reserve margin levels for the Base Case. Figure ES1 shows the risk neutral costs at the various winter reserve margin levels. This risk neutral represents the weighted average results of all weather years, load forecast uncertainty, and

[12] System costs = system energy costs plus capacity costs of incremental reserves. System energy costs include production costs + net purchases + loss of reserves costs + unserved energy costs while system capacity costs include the fixed capital and fixed operations & maintenance (FOM) costs for CT capacity. Unserved energy costs equal the value of lost load times the expected unserved energy

unit performance iterations at each reserve margin level and represents the yearly expected value on a year in and year out basis.

Figure ES1. Base Case Risk Neutral Economic Results[13]



As Figure ES1 shows, the lowest risk neutral cost falls at a 15.00% reserve margin very close to the one day in 10-year standard (LOLE of 0.1). These values are close because the summer reserve margins are only slightly higher than the winter reserve margins which increases the savings of adding additional CT capacity.[14] The cost curve is fairly flat for a large portion of the reserve margin curve because when CT capacity is added there is always system energy cost savings from

[13] Costs that are included in every reserve margin level have been removed so the reader can see the incremental impact of each category of costs. DEC has approximately 1.5 billion dollars in total costs.
[14] This is different than the results seen in DEP because DEP's summer reserves margins are much greater than its winter reserves margins causing CTs to provide less economic benefit in DEP than DEC.

either reduction in loss of load events, savings in purchases, or savings in production costs. This risk neutral scenario represents the weighted average of all scenarios but does not illustrate the impact of high-risk scenarios that could cause customer rates to be volatile from year to year. Figure ES2, however, shows the distribution of system energy costs which includes production costs, purchase costs, loss of reserves costs, and expected unserved energy (EUE) at different reserve margin levels. This figure excludes fixed CT costs which increase with reserve margin level. As reserves are added, system energy costs decline. By moving from lower reserve margin levels to higher reserve margin levels, the volatile right side of the curve (greater than 85% Cumulative Probability) is dampened, shielding customers from extreme scenarios for relatively small increases in annual expected costs. By paying for additional CT capacity, extreme scenarios are mitigated.

Figure ES2. System Energy Costs (Cumulative Probability Curves)

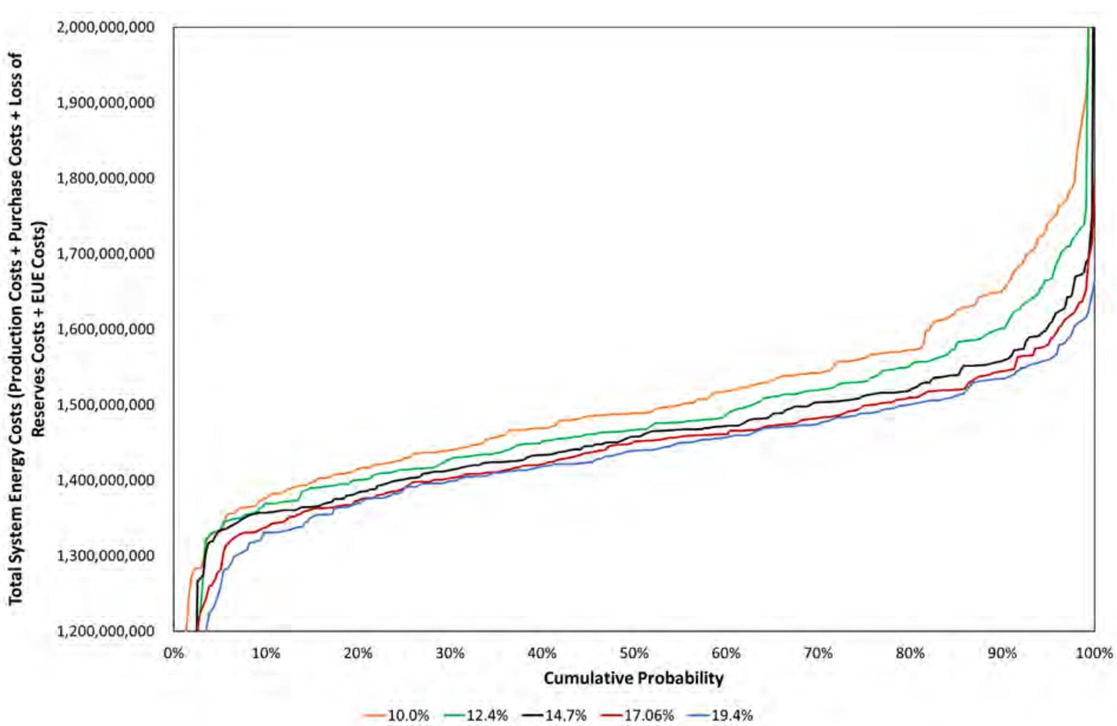


Table ES5 shows the same data laid out in tabular format. It includes the weighted average results as shown in Figure ES1 as well as the energy savings at higher cumulative probability levels from Figure ES2. As shown in the table, going from the risk neutral reserve margin of 15.00% to 17% increases customer costs on average by $2.9 million a year[15] and reduces LOLE from 0.12 to 0.08 events per year. The LOLE for the island scenario decreases from 0.68 days per year to 0.41 days per year. However, 10% of the time energy savings are greater than or equal to $21 million if a 17% reserve margin is maintained versus the 15.00% reserve margin. While 5 % of the time, $34 million or more is saved.

Table ES5. Annual Customer Costs vs LOLE

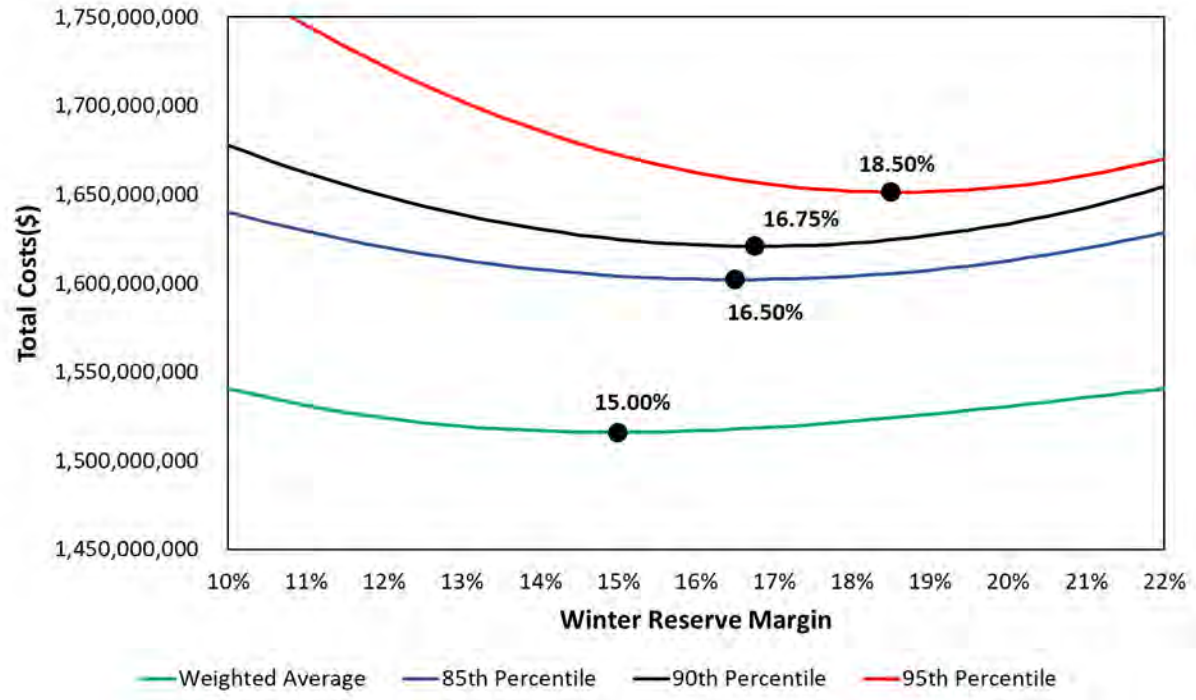
Reserve Margin	Change in Capital Costs ($M)	Change in Energy Costs ($M)	Total Weighted Average Costs ($M)	85th Percentile Change in Energy Costs ($M)	90th Percentile Change in Energy Costs ($M)	95th Percentile Change in Energy Costs ($M)	LOLE (Days Per Year)	LOLE (Days Per Year) Island Sensitivity
15.00%	-	-	-	-	-	-	0.12	0.68
16.00%	8.5	-7.8	0.8	-10.4	-11.7	-18.6	0.1	0.52
17.00%	17.1	-14.2	2.9	-19.0	-21.0	-34.0	0.08	0.41
18.00%	25.6	-19.5	6.1	-25.8	-27.8	-46.1	0.07	0.33
19.00%	34.2	-24.0	10.1	-30.8	-32.1	-55.0	0.06	0.26
20.00%	42.7	-28.0	14.7	-34.1	-33.9	-60.6	0.05	0.20

The next figure takes the 85th, 90th, and 95th percentile points of the total system energy costs in Figure ES2 and adds them to the fixed CT costs at each reserve margin level. It is rational to view the data this way because CT costs are more known with a small band of uncertainty while the system energy costs are volatile as shown in the previous figure. In order to attempt to put the fixed costs and the system energy costs on a similar basis in regards to uncertainty, higher

[15] This includes $17 million for additional CT costs less $14 million of system energy savings.

cumulative probability points using the 85th – 95th percentile range can be considered for the system energy costs. While the risk neutral lowest cost curve falls at 15.00% reserve margin, the 85th to 95th percentile cost curves point to a 16-19% reserve margin.

Figure ES3. Total System Costs by Reserve Margin.



Carrying additional capacity above the risk neutral reserve margin level to reduce the frequency of firm load shed events in DEC is similar to the way PJM incorporates its capacity market to maintain the one day in 10-year standard (LOLE of 0.1). In order to maintain reserve margins that meet the one day in 10-year standard (LOLE of 0.1), PJM supplies additional revenues to generators through its capacity market. These additional generator revenues are paid by customers who in turn see enhanced system reliability and lower energy costs. At much lower reserve margin levels, generators can recover fixed costs in the market due to capacity shortages and more frequent high prices seen during these periods, but the one day in 10-year standard (LOLE of 0.1) target is not satisfied.

Sensitivity Results

Various sensitivities were run in addition to the Base Case to examine the reliability and cost impact of different assumptions and scenarios. Table ES6 lists the various sensitivities and the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) as well as economic results of each. These include sensitivities around cold weather generator outages, load forecast error uncertainty, solar penetration, the cost of unserved energy, the cost of CT capacity, demand response, coal retirements, and climate change. Detailed explanations of each sensitivity are available in the body of the report. The target reserve margin to meet the one day in 10-year standard (LOLE of 0.1) ranged from 14.75% to 17.25% depending on the sensitivity simulated.

Table ES6. Sensitivity Results

Sensitivity	1 in 10 LOLE Reserve Margin	Economic Risk Neutral	Economic 90th Percentile
Base Case	16.00%	15.00%	16.75%
No Cold Weather Outages	14.75%	14.75%	16.75%
Cold Weather Outages based on 2014 - 2019	17.25%	15.00%	17.00%
Remove LFE	16.25%	15.00%	16.00%
Originally Proposed Normal Distribution	17.00%	16.00%	18.00%
Low Solar	16.00%	16.00%	18.25%
High Solar	15.75%	14.00%	14.50%
CT costs 40 $/kW-yr	16.00%	16.00%	17.25%
CT costs 60 $/kW-yr	16.00%	13.75%	16.00%
EUE 5,000 $/MWh	16.00%	14.50%	16.25%
EUE 25,000 $/MWh	16.00%	15.25%	16.75%
Demand Response Winter as High as Summer	16.75%	18.25%	19.50%
Retire all Coal	15.25%	17.00%	20.25%
Climate Change	15.75%	14.25%	16.75%

Recommendation

Based on the physical reliability results of the Island, Base Case, Combined Case, additional sensitivities, as well as the results of the separate DEP Study, Astrapé recommends that DEC continue to maintain a minimum 17% reserve margin for IRP purposes. This reserve margin ensures reasonable reliability for customers. Astrapé recognizes that a standalone DEC utility would require a 22.5% reserve margin to meet the one day in 10-year standard (LOLE of 0.1) and that with market assistance, DEC would need to maintain a 16.00% reserve margin. However, given the combined DEC and DEP sensitivity resulting in a 16.75% reserve margin, and the 19.25% reserve margin required by DEP to meet the one day in 10-year standard (LOLE of 0.1), Astrapé believes the 17% reserve margin as a minimum target for both DEC and DEP is still reasonable for planning purposes. Since the sensitivity results removing all economic load forecast uncertainty increase the reserve margin to meet the 1 day in 10-year standard, Astrapé believes this 17% minimum reserve margin should be used in the short- and long-term planning process.

To be clear, even with 17% reserves, this does not mean that DEC will never be forced to shed firm load during extreme conditions as DEC and its neighbors shift to reliance on intermittent and energy limited resources such as storage and demand response. DEC has had several events in the past few years where actual operating reserves were close to being exhausted even with higher than 17% planning reserve margins. If not for non-firm external assistance which this study considers, firm load would have been shed. In addition, incorporation of tail end reliability risk in modeling should be from statistically and historically defendable methods; not from including subjective risks that cannot be assigned probability. Astrapé's approach has been to model the system's risks around weather, load, generator performance, and market assistance as accurately as possible without overly conservative assumptions. Based on all results, Astrapé believes planning to a 17% reserve margin is prudent from a physical reliability perspective and for small increases in costs above the risk-neutral 15% reserve margin level, customers will experience enhanced reliability and less rate volatility.

As the DEC resource portfolio changes with the addition of more intermittent resources and energy limited resources, the 17% minimum reserve margin is sufficient as long as the Company has accounted for the capacity value of solar and battery resources which changes as a function of penetration. DEC should also monitor changes in the IRPs of neighboring utilities and the potential impact on market assistance. Unless DEC observes seasonal risk shifting back to summer, the 17% reserve margin should be reasonable but should be re-evaluated as appropriate in future IRPs and in future reliability studies. To ensure summer reliability is maintained, Astrapé recommends not allowing the summer reserve margin to drop below 15%.[16]

[16] Currently, if a winter target is maintained at 17%, summer reserves will be above 15%.

I. List of Figures

II. List of Tables

III. Input Assumptions

A. Study Year

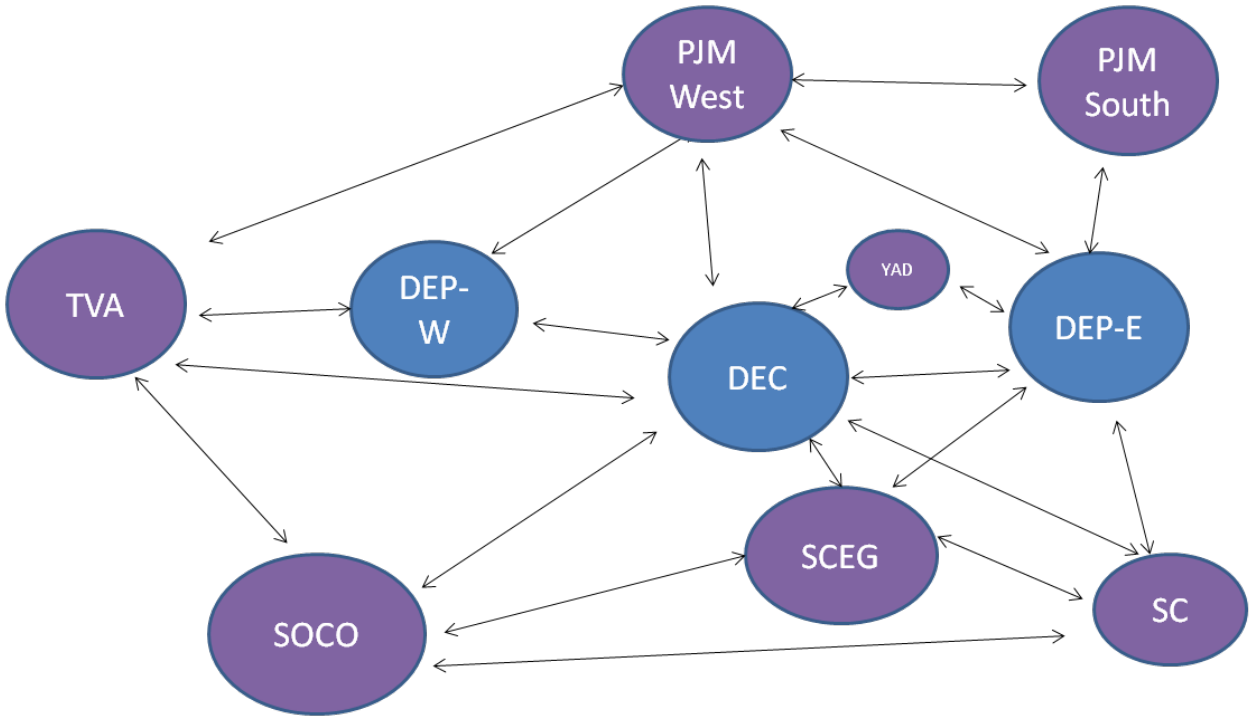
The selected study year is 2024[17]. The SERVM simulation results are broadly applicable to future years assuming that resource mixes and market structures do not change in a manner that shifts the reliability risk to a different season or different time of day.

B. Study Topology

Figure 1 shows the study topology that was used for the Resource Adequacy Study. While market assistance is not as dependable as resources that are utility owned or have firm contracts, Astrapé believes it is appropriate to capture the load diversity and generator outage diversity that DEC has with its neighbors. For this study, the DEC system was modeled with nine surrounding regions. The surrounding regions captured in the modeling included Duke Energy Progress (DEP) which was modeled in two interconnect zones: (1) DEP – E and (2) DEP – W, Tennessee Valley Authority (TVA), Southern Company (SOCO), PJM West &PJM South, Yadkin (YAD), Dominion Energy South Carolina (formally known as South Carolina Electric & Gas (SCEG)), and Santee Cooper (SC). SERVM uses a pipe and bubble representation in which energy can be shared based on economics but subject to transmission constraints.

[17] The year 2024 was chosen because it is four years into the future which is indicative of the amount of time needed to permit and construct a new generating facility.

Figure 1. Study Topology



Confidential Appendix Table CA1 displays the DEC import capability from surrounding regions including the amount set aside for Transmission Reliability Margin (TRM).

C. Load Modeling

Table 1 displays SERVM's modeled seasonal peak forecast net of energy efficiency programs for 2024.

Table 1. 2024 Forecast: DEC Seasonal Peak (MW)

2024 Summer	18,456 MW
2024 Winter	17,976 MW

To model the effects of weather uncertainty, thirty-nine historical weather years (1980 - 2018) were developed to reflect the impact of weather on load. Based on the last five years of historical weather and load[18], a neural network program was used to develop relationships between weather observations and load. The historical weather consisted of hourly temperatures from three weather stations across the DEC service territory. The weather stations included Charlotte, NC, Greensboro, NC, and Greenville, SC. Other inputs into the neural net model consisted of hour of week, eight hour rolling average temperatures, twenty-four hour rolling average temperatures, and forty-eight hour rolling average temperatures. Different weather to load relationships were built for the summer, winter, and shoulder seasons. These relationships were then applied to the last thirty-nine years of weather to develop thirty-nine synthetic load shapes for 2024. Equal probabilities were given to each of the thirty-nine load shapes in the simulation. The synthetic load shapes were scaled to align the normal summer and winter peaks to the Company's projected thirty-year weather normal load forecast for 2024.

Figures 2 and 3 show the results of the 2014-2019 weather load modeling by displaying the peak load variance for both the summer and winter seasons. The y-axis represents the percentage deviation from the average peak. For example, the 1985 synthetic load shape would result in a summer peak load approximately 2% below normal and a winter peak load approximately 18% above normal. Thus, the bars represent the variance in projected peak loads based on weather experienced during the historic weather years. It should be noted that the variance for winter is much greater than summer. As an example, extreme cold temperatures can cause load to spike from additional electric strip heating. The highest summer temperatures typically are only a few degrees above the expected highest temperature and therefore do not produce as much peak load variation.

[18] The historical load included years 2014 through September of 2019.

Figure 2. DEC Summer Peak Weather Variability

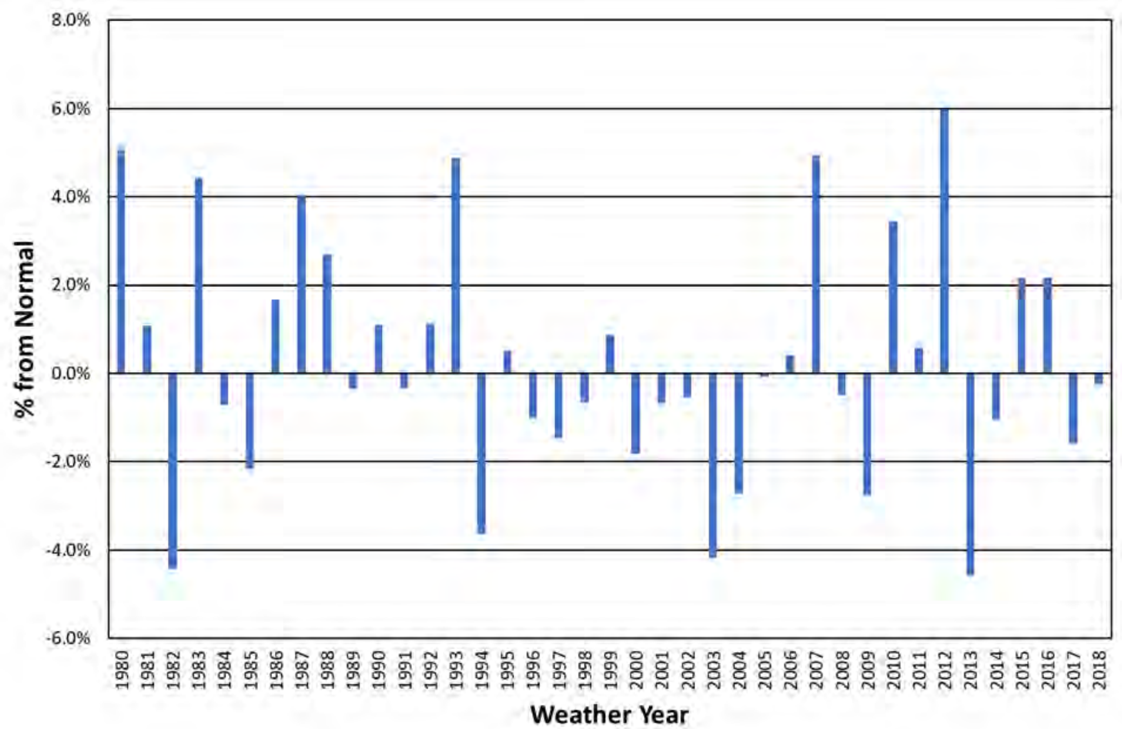


Figure 3. DEC Winter Peak Weather Variability

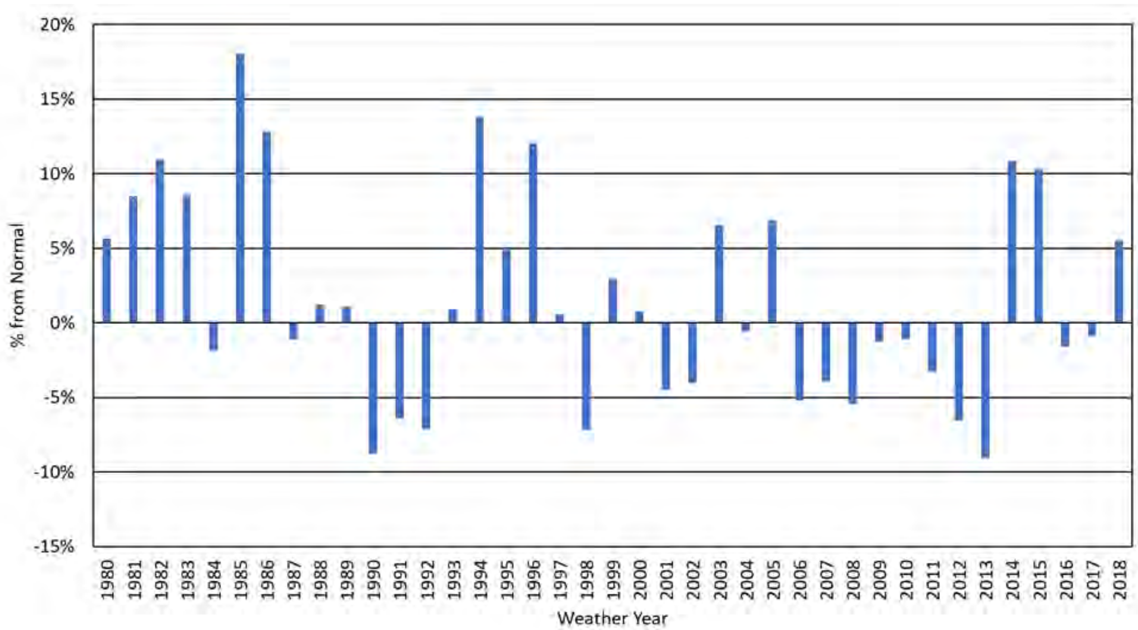
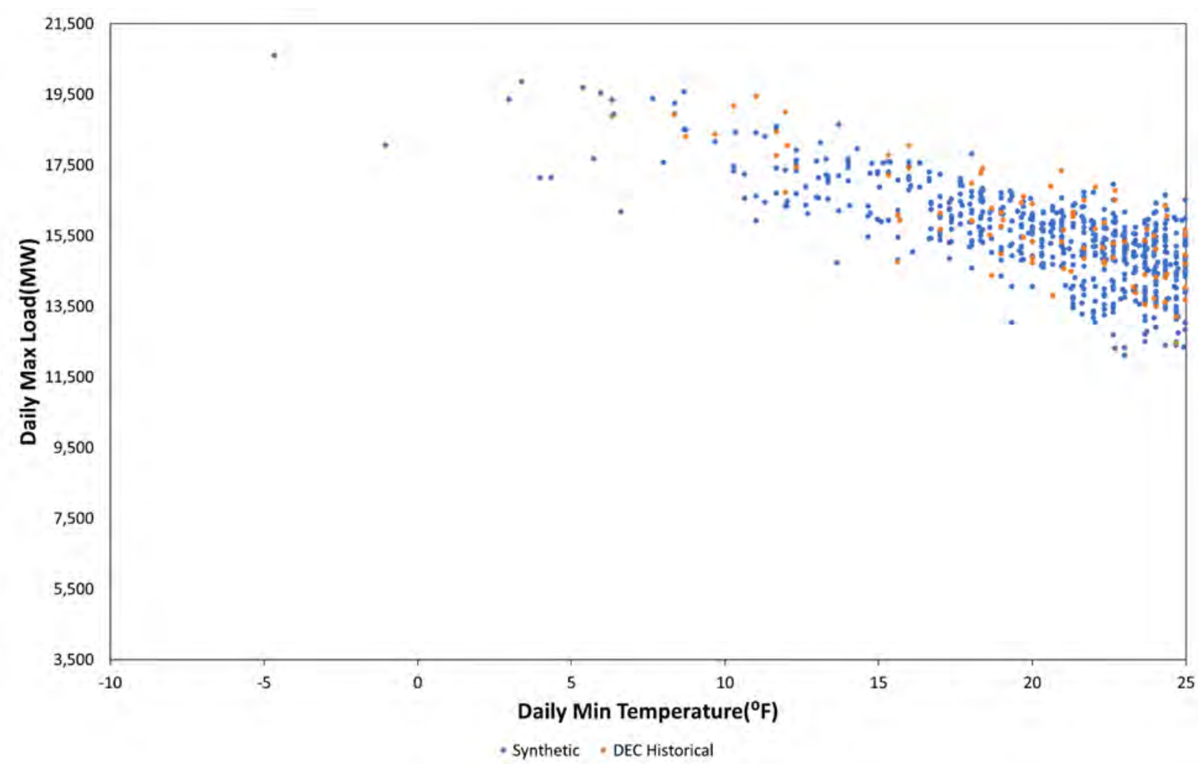


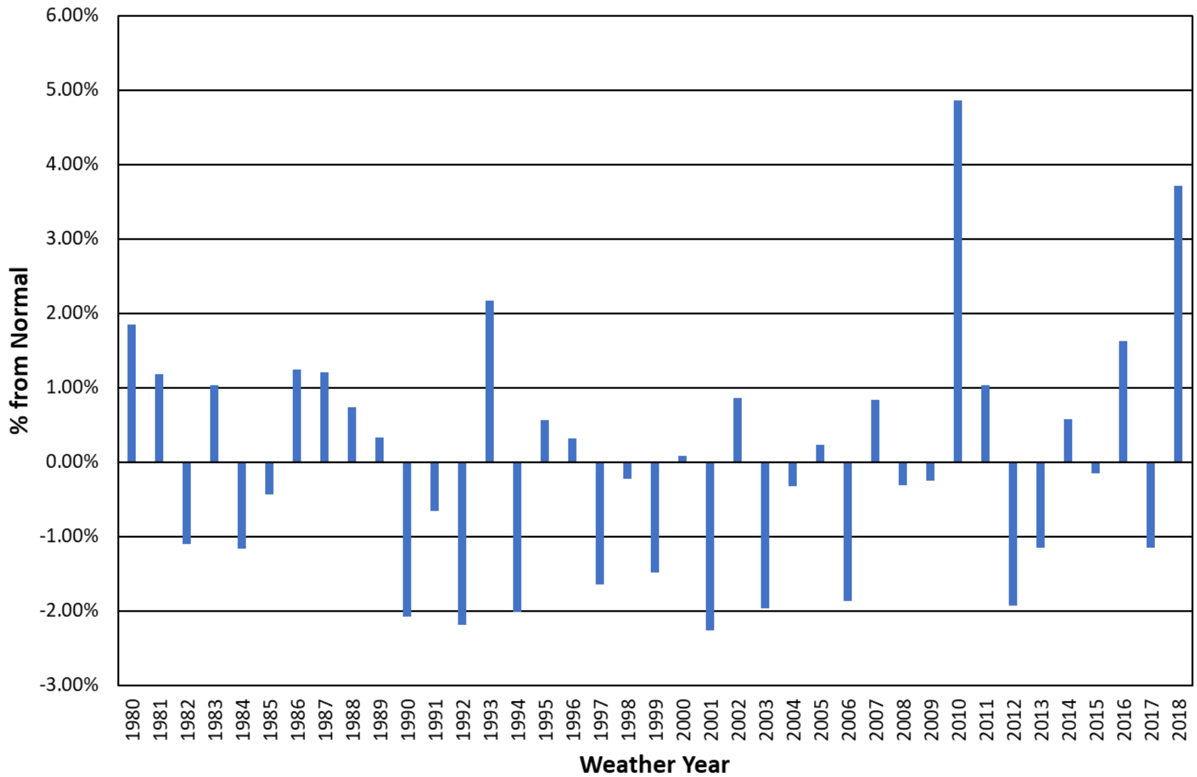
Figure 4 shows a daily peak load comparison of the synthetic load shapes and DEC history as a function of temperature. The predicted values align well with the history. Because recent historical observations only recorded a single minimum temperature of six degrees Fahrenheit, Astrapé estimated the extrapolation for extreme cold weather days using regression analysis on the historical data. This figure highlights that the frequency of cold weather events is captured as it has been seen in history.

Figure 4. DEC Winter Calibration



The energy variation is lower than peak variation across the weather years as expected. As shown in Figure 5, 2010 was an extreme year in total energy due to persistent severe temperatures across the summer and yet the deviation from average was only 5%.

Figure 5. DEC Annual Energy Variability



The synthetic shapes described above were then scaled to the forecasted seasonal energy and peaks within SERVM. Because DEC's load forecast is based on thirty years of weather, the shapes were scaled so that the average of the last thirty years equaled the forecast.

Synthetic loads for each external region were developed in a similar manner as the DEC loads. A relationship between hourly weather and publicly available hourly load[19] was developed based on

[19] Federal Energy Regulatory Commission (FERC) 714 Forms were accessed during January of 2020 to pull hourly historical load for all neighboring regions.

recent history, and then this relationship was applied to thirty-nine years of weather data to develop thirty-nine synthetic load shapes. Tables 2 and 3 show the resulting weather diversity between DEC and external regions for both summer and winter loads. When the system, which includes all regions in the study, is at its winter peak, the individual regions are approximately 2% - 9% below their non-coincidental peak load on average over the thirty-nine year period, resulting in an average system diversity of 4.7%. When DEC is at its winter peak load, DEP is 2.8% below its peak load on average while other regions are approximately 3% - 11% below their winter peak loads on average. Similar values are seen during the summer.

Table 2. External Region Summer Load Diversity

Load Diversity (% below non coincident average peak)	DEC	DEP	SOCO	TVA	SC	SCEG	PJM S	PJM W	System
At System Coincident Peak	3.4%	3.8%	5.2%	4.2%	6.8%	7.0%	3.7%	1.4%	N/A
At DEC Peak	N/A	2.6%	7.0%	4.8%	5.7%	7.5%	4.5%	6.9%	2.3%

Table 3. External Region Winter Load Diversity

Load Diversity (% below non coincident average peak)	DEC	DEP	SOCO	TVA	SC	SCEG	PJM S	PJM W	System
At System Coincident Peak	2.5%	2.8%	2.8%	5.8%	8.9%	4.8%	6.9%	3.2%	N/A
At DEC Peak	N/A	2.8%	3.0%	5.8%	9.2%	5.9%	7.0%	11.0%	2.8%

D. Economic Load Forecast Error

Economic load forecast error multipliers were developed to isolate the economic uncertainty that Duke has in its four year ahead load forecasts. Four years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans. To estimate the economic load forecast error, the difference between Congressional Budget Office (CBO) Gross Domestic Product (GDP) forecasts four years ahead and actual data was fit to a distribution which weighted over-forecasting more heavily than under-forecasting load[20]. This was a direct change accepted as part of the feedback in stakeholder meetings.[21] Because electric load grows at a slower rate than GDP, a 40% multiplier was applied to the raw CBO forecast error distribution. Table 4 shows the economic load forecast multipliers and associated probabilities. As an illustration, 25% of the time, it is expected that load will be over-forecasted by 2.7% four years out. Within the simulations, when DEC over-forecasts load, the external regions also over-forecast load. The SERVM model utilized each of the thirty-nine weather years and applied each of these five load forecast error points to create 195 different load scenarios. Each weather year was given an equal probability of occurrence.

Table 4. Load Forecast Error

Load Forecast Error Multipliers	Probability %
0.958	10.0%
0.973	25.0%
1.00	40.0%
1.02	15.0%
1.031	10.0%

[20] CBO's Economic Forecasting Record: 2017 Update. www.cbo.gov/publication/53090
www.cbo.gov/publication/53090
[21] Including the economic load forecast uncertainty actually results in a lower reserve margin compared to a scenario that excludes the load forecast uncertainty since over-forecasting load is weighted more heavily than under-forecasting load.

E. Conventional Thermal Resources

DEC resources are outlined in Tables 5 and 6 and represent summer ratings and winter ratings. All thermal resources are committed and dispatched to load economically. The capacities of the units are defined as a function of temperature in the simulations. Full winter rating is achieved at 35°F and below and summer rating is assumed for 95° and above. For temperatures in between 35°F and 95°F, a simple linear regression between the summer and winter rating was utilized for each unit.

Table 5. DEC Baseload and Intermediate Resources

Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)	Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)
Allen 1	Coal	162	167	Marshall 4	Coal	660	660
Allen 2	Coal	162	167	Catawba 1	Nuclear	260	294
Allen 3	Coal	258	270	Catawba 2	Nuclear	260	294
Allen 4	Coal	257	267	McGuire 1	Nuclear	1158	1199
Allen 5	Coal	259	259	McGuire 2	Nuclear	1158	1187
Belews Creek 1	Coal	1110	1110	Oconee 1	Nuclear	847	865
Belews Creek 2	Coal	1110	1110	Oconee 2	Nuclear	848	872
Cliffside 5	Coal	554	546	Oconee 3	Nuclear	859	881
Cliffside 6	Coal	844	849	Buck CC	Combined Cycle	668	716
Marshall 1	Coal	370	380	Dan River CC	Combined Cycle	662	718
Marshall 2	Coal	370	380	Lee CC	Combined Cycle	686	692
Marshall 3	Coal	658	658	Lee NG Conversion	Natural Gas	160	173

Table 6. DEC Peaking Resources

Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)	Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)
Lincoln CT_1	NG Peaker	76	98	Lee CT_1	Oil Peaker	42	48
Lincoln CT_2	NG Peaker	76	99	Lee CT_2	Oil Peaker	42	48
Lincoln CT_3	NG Peaker	75	99	Mill_Creek_CT_1	NG Peaker	71	95
Lincoln CT_4	NG Peaker	75	98	Mill_Creek_CT_2	NG Peaker	70	95
Lincoln CT_5	NG Peaker	74	97	Mill_Creek_CT_3	NG Peaker	71	95
Lincoln CT_6	NG Peaker	73	97	Mill_Creek_CT_4	NG Peaker	70	96
Lincoln CT_7	NG Peaker	75	98	Mill_Creek_CT_5	NG Peaker	69	96
Lincoln CT_8	NG Peaker	75	98	Mill_Creek_CT_6	NG Peaker	71	92
Lincoln CT_9	NG Peaker	75	97	Mill_Creek_CT_7	NG Peaker	70	95
Lincoln CT_10	NG Peaker	75	98	Mill_Creek_CT_8	NG Peaker	71	93
Lincoln CT_11	NG Peaker	74	98	Rockingham 1	NG Peaker	165	179
Lincoln CT_12	NG Peaker	75	98	Rockingham 2	NG Peaker	165	179
Lincoln CT_13	NG Peaker	74	98	Rockingham 3	NG Peaker	165	179
Lincoln CT_14	NG Peaker	74	97	Rockingham 4	NG Peaker	165	179
Lincoln CT_15	NG Peaker	73	98	Rockingham 5	NG Peaker	165	179
Lincoln CT_16	NG Peaker	73	97				

DEC purchase contracts were modeled as shown in Confidential Appendix Table CA2. These resources were treated as traditional thermal resources and counted towards reserve margin. Confidential Appendix Table CA3 shows the fuel prices used in the study for DEC and its neighboring power systems.

F. Unit Outage Data

Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical Generating Availability Data System (GADS) data events for the period 2014-2019 are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. Units without historical data use history from similar technologies. The events are entered using the following variables:

Full Outage Modeling
Time-to-Repair Hours
Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

Maintenance Outages
Maintenance Outage Rate - % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods.

Planned Outages
The actual schedule for 2024 was used.

To illustrate the outage logic, assume that from 2014 – 2019, a generator had 15 full outage events and 30 partial outage events reported in the GADS data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data. These multiple Time-to-Repair and Time-to-Fail inputs are the distributions used by SERVM. Because there may be seasonal variances in EFOR, the data is broken up into seasons such that there is a set of Time-to-Repair and Time-to-Fail inputs for summer, shoulder, and winter, based on history. Further, assume the generator is online in hour 1 of the simulation. SERVM will randomly draw both a full outage and partial outage Time-to-Fail value from the distributions provided. Once the unit has been economically dispatched for that amount of time, it will fail. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. The full outage counters and partial outage counters run in parallel. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture. Confidential Appendix Table CA4 shows system peak season Equivalent Forced Outage Rate (EFOR) for the system and by unit.

The most important aspect of unit performance modeling in resource adequacy studies is the cumulative MW offline distribution. Most service reliability problems are due to significant coincident outages. Confidential Appendix Figure CA1 shows the distribution of modeled system outages as a percentage of time modeled and compared well with actual historical data.

Additional analysis was performed to understand the impact cold temperatures have on system outages. Confidential Appendix Figures CA2 and CA3 show the difference in cold weather outages during the 2014-2019 period and the 2016-2019 period. The 2014-2019 period showed more events than the 2016-2019 period which is logical because Duke Energy has put practices in place to enhance reliability during these periods, however the 2016 – 2019 data shows some events still occur. The average capacity offline below 10 degrees for DEC and DEP combined was 400 MW. Astrapé split this value by peak load ratio and included 260 MW in the DEC Study and 140 MW in the DEP Study at temperatures below 10 degrees. Sensitivities were performed with the cold weather outages removed and increased to match the 2014 – 2019 dataset which showed an average of 800 MW offline on days below 10 degrees. The MWs offline during the 10 coldest days can be seen in Confidential Appendix Table CA5. The outages shown are only events that included some type of freezing or cold weather problem as part of the description in the outage event.

G. Solar and Battery Modeling

Table 7 shows the solar and battery resources captured in the study.

Table 7. DEC Renewable Resources Excluding Existing Hydro

Unit Type	Summer Capacity (MW)	Winter Capacity (MW)	Modeling
Utility Owned-Fixed	85	85	Hourly Profiles
Transition-Fixed	660	660	Hourly Profiles
CPRE Tranche 1 Fixed 40%/Tracking 60%	465	465	Hourly Profiles
Future Solar Fixed 40%/Tracking 60%	1,368	1,368	Hourly Profiles
Total	2,578	2,578	
Total Battery	146	146	Modeled as energy arbitrage

The solar units were simulated with thirty-nine solar shapes representing thirty-nine years of weather. The solar shapes were developed by Astrapé from data downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) Data Viewer. The data was then input into NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles for both fixed and tracking solar profiles. The solar capacity was given 37% credit in the summer and 1% in the winter for reserve margin calculations based on the 2018 Solar Capacity Value Study. The following figure shows the county locations that were used and Figure 7 shows the average August output for different fixed-tilt and single-axis-tracking inverter loading ratios.

Figure 6. Solar Map

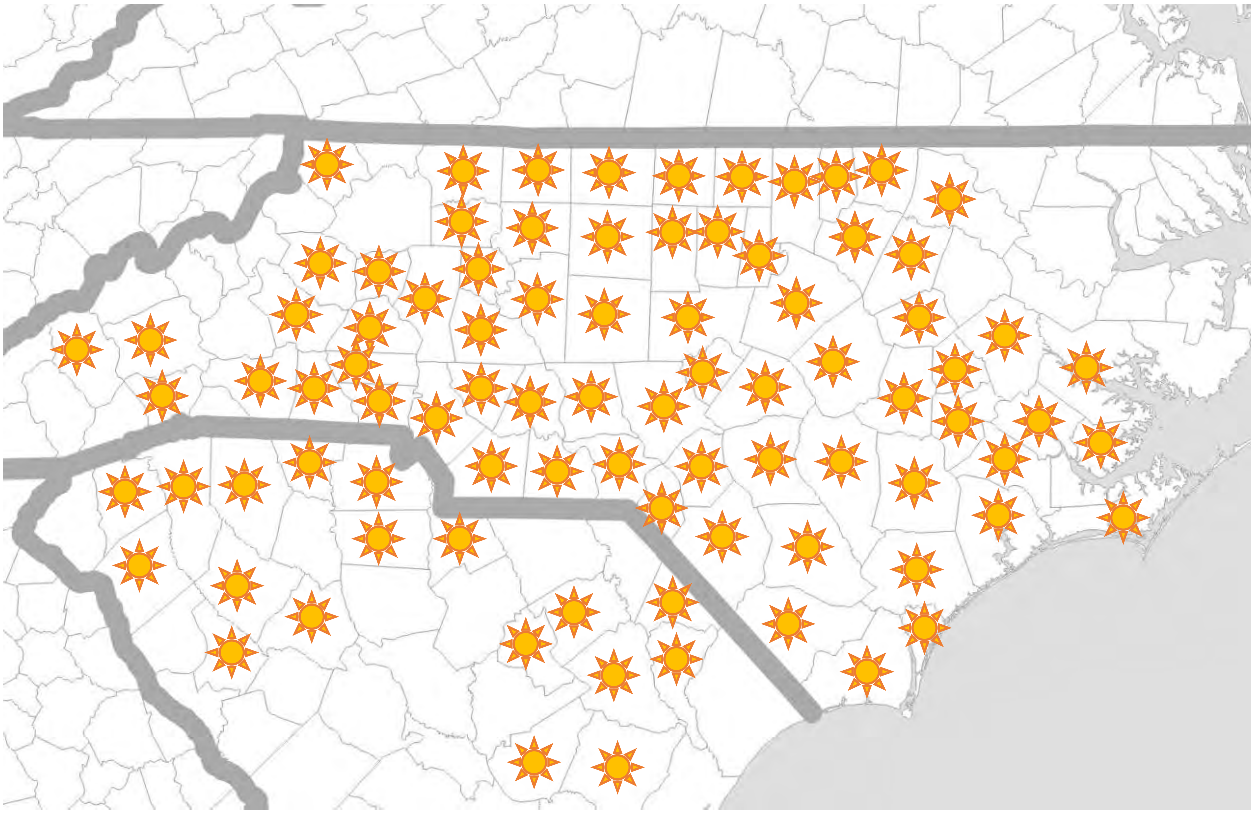
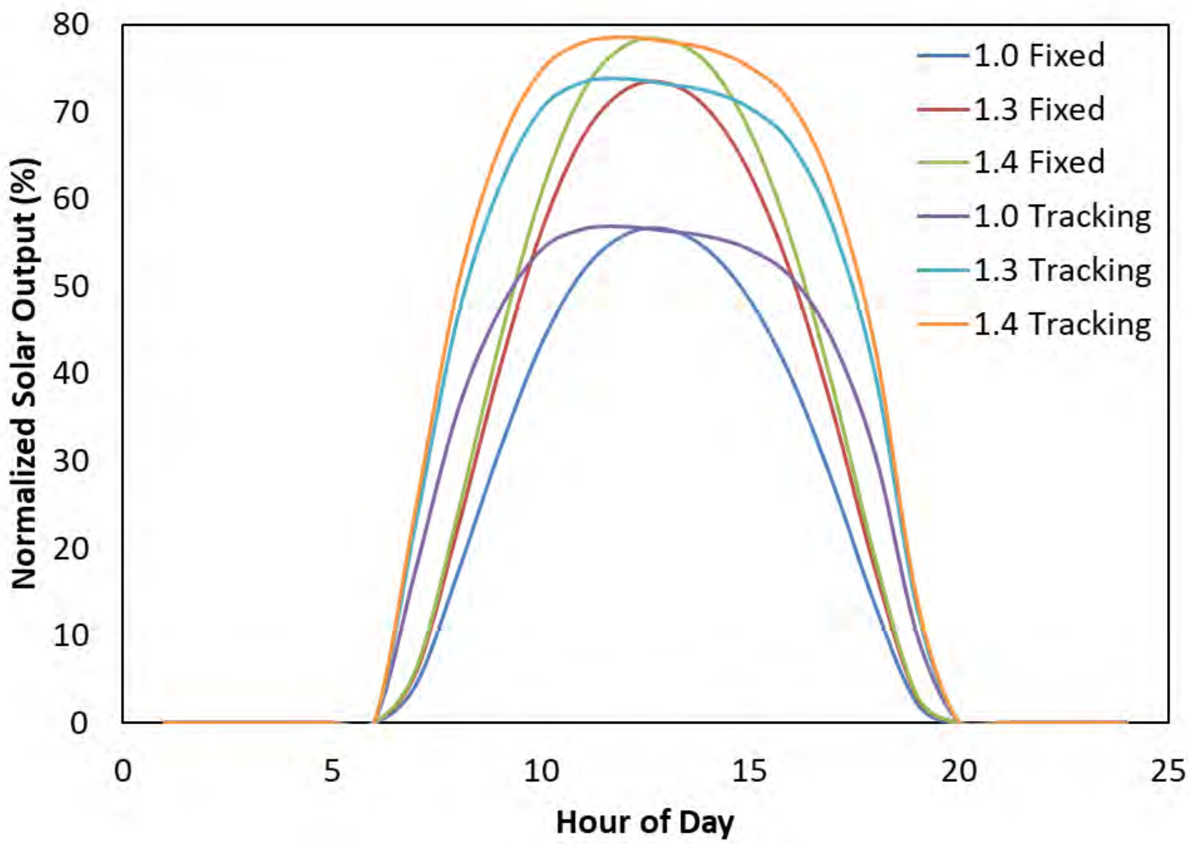


Figure 7. Average August Output for Different Inverter Loading Ratios



H. Hydro Modeling

The scheduled hydro is used for shaving the daily peak load but also includes minimum flow requirements. Figure 8 shows the total breakdown of scheduled hydro based on the last thirty-nine years of weather.

Figure 8. Scheduled Capacity

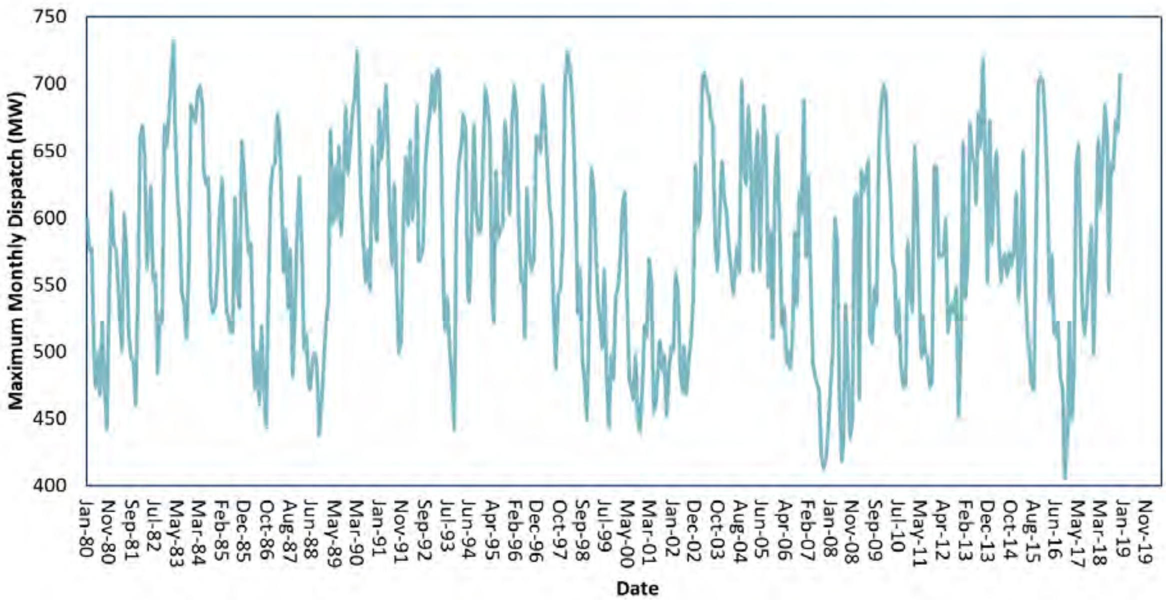
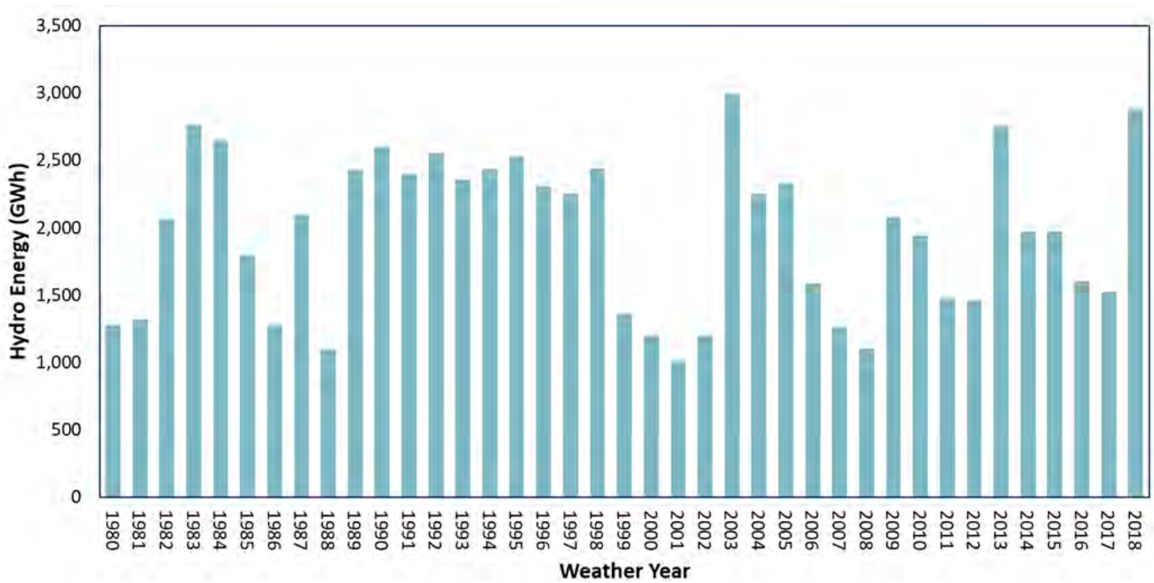


Figure 9 demonstrates the variation of hydro energy by weather year which is input into the model. The lower rainfall years such as 2001, 2007, and 2008 are captured in the reliability model with lower peak shaving as shown in Figure 9.

Figure 9. Hydro Energy by Weather Year



In addition to conventional hydro, DEC owns and operates a pump hydro fleet consisting of 2,400 MW. The fleet consists of two pump storage plants: (1) Bad Creek at a 1,620 MW summer/winter rating and (2) Jocassee at a 780 MW summer/winter rating. These resources are modeled with reservoir capacity, pumping efficiency, pumping capacity, generating capacity, and forced outage rates[22]. SERVM uses excess capacity to economically fill up the reservoirs to ensure the generating capacity is available during peak conditions.

I. Demand Response Modeling

Demand response programs are modeled as resources in the simulations. They are modeled with specific contract limits including hours per year, days per week, and hours per day constraints. For this study, 1,122 MW of summer capacity and 442 MW of winter capacity were included as shown in Table 8. To ensure these resources were called after conventional generation, a $2,000/MWh strike price was included.

[22] See Confidential Appendix Table CA4

Table 8. DEC Demand Response Modeling

Region	Program	Summer Capacity (MW)	Winter Capacity (MW)	Hours Per Year	Days Per Week	Hours Per Day
DEC	PowerShare Mandatory	355	331	150	7	24
DEC	PowerShare Generator	11	10	100	7	10
DEC	Power Manager DLC	608	0	100	7	10
DEC	IS	94	89	150	7	10
DEC	Energy Wise Business	46	4	60	7	4
DEC	SG	8	8	150	7	24
	Total DEC	1,122	442			

J. Operating Reserve Requirements

The operating reserves assumed for DEC are shown below. SERVM commits to this level of operating reserves in all hours. However, all operating reserves except for the 218 MW of regulation are allowed to be depleted during a firm load shed event.

- Regulation Up/Down: 218 MW
- Spinning Requirement: 275 MW
- Non-Spin Requirement: 275 MW
- Additional Load Following Due to Intermittent Resources in 2024: Hourly values were used based on a 12x24 profile provided by Duke Energy from its internal modeling.

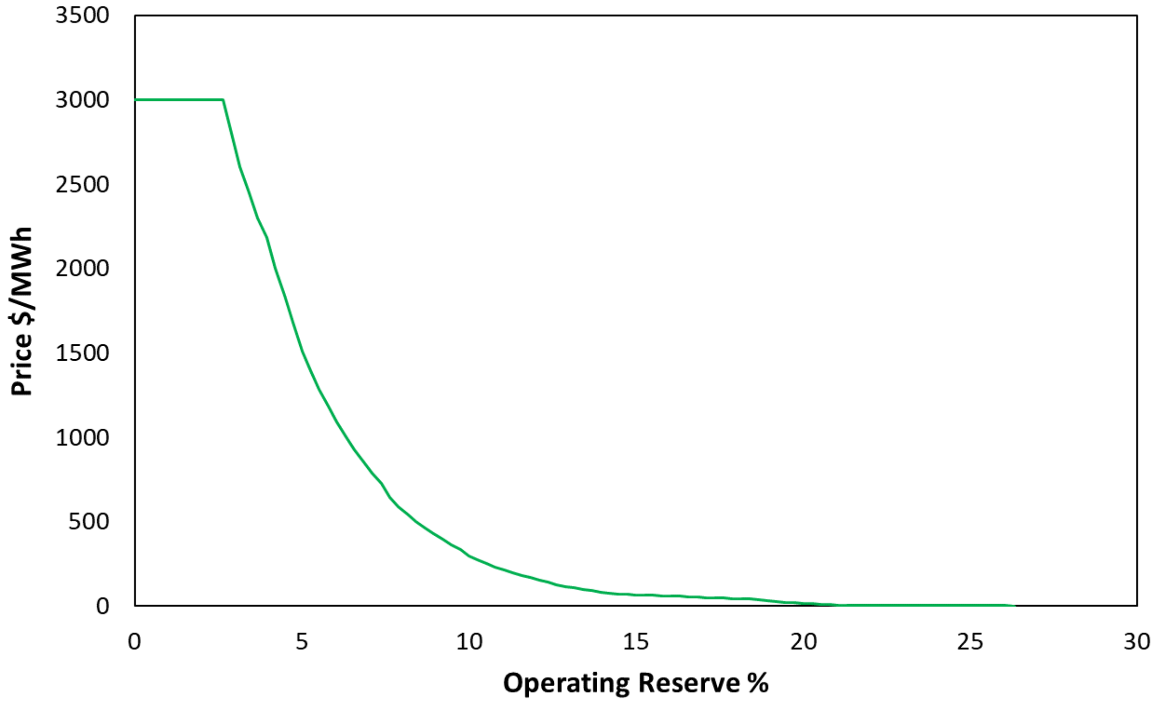
K. External Assistance Modeling

The external market plays a significant role in planning for resource adequacy. If several of the DEC resources were experiencing an outage at the same time, and DEC did not have access to surrounding markets, there is a high likelihood of unserved load. To capture a reasonable amount of assistance from surrounding neighbors, each neighbor was modeled at the one day in 10-year standard (LOLE of 0.1) level representing the target for many entities. By modeling in this manner, only weather diversity and generator outage diversity benefits are captured. The market representation used in SERVM is based on Astrapé's proprietary dataset which is developed based on FERC Forms, Energy Information Administration (EIA) Forms, and reviews of IRP information from neighboring regions. To ensure purchases in the model compared well in magnitude to historical data, the years 2015 and 2018 were simulated since they reflected cold weather years with high winter peaks. Figure CA4 in the confidential appendix shows that calibration with purchases on the y-axis and load on the x-axis for the 2015 and 2018 weather years. The actual purchases and modeled results show DEC purchases significant capacity during high load hours during these years.

The cost of transfers between regions is based on marginal costs. In cases where a region is short of resources, scarcity pricing is added to the marginal costs. As a region's hourly reserves approach zero, the scarcity pricing for that region increases. Figure 10 shows the scarcity pricing curve that was used in the simulations. It should be noted that the frequency of these scarcity prices is very low because in the majority of hours, there is plenty of capacity to meet load after the market has cleared[23].

[23]The market clearing algorithm within SERVM attempts to get all regions to the same price subject to transmission constraints. So, if a region's original price is $3,000/MWh based on the conditions and scarcity pricing in that region alone, it is highly probable that a surrounding region will provide enough capacity to that region to bring prices down to reasonable levels.

Figure 10. Operating Reserve Demand Curve (ORDC)



L. Cost of Unserved Energy

Unserved energy costs were derived from national studies completed for the Department of Energy (DOE) in 2003[24] and 2009[25], along with three other studies performed[26] previously by other consultants. The DOE studies were compilations of other surveys performed by utilities over the last two decades. All studies split the customer class categories into residential, commercial, and industrial. The values were then applied to the actual DEC customer class mix to develop a wide range of costs for unserved energy. Table 9 shows those results. Because expected unserved

[24] https://eta-publications.lbl.gov/sites/default/files/lbnl-54365.pdf https://eta-publications.lbl.gov/sites/default/files/lbnl-54365.pdf
[25] https://eta-publications.lbl.gov/sites/default/files/lbnl-2132e.pdf https://eta-publications.lbl.gov/sites/default/files/lbnl-2132e.pdf
[26] https://pdfs.semanticscholar.org/544b/d740304b64752b451d749221a00eede4c700.pdf
Peter Cramton, Jeffrey Lien. Value of Lost Load. February 14, 2000.

energy costs are so low near the economic optimum reserve margin, this value, while high in magnitude, is not a significant driver in the economic analysis. Since the public estimates ranged significantly, DEC used $18,160/MWh for the Base Case in 2024, and sensitivities were performed around this value from $5,000 MWh to $25,000 MWh to understand the impact.

Table 9. Unserved Energy Costs / Value of Lost Load

	Weightings	2003 DOE Study 2024 $/kW-yr	2009 DOE Study 2024 $/kW-yr	Christiansen Associates 2024 $/kW-yr	Billinton and Wacker 2024 $/kW-yr	Karuiki and Allan 2024 $/kW-yr
Residential	36%	1.57	1.50	3.12	2.73	1.26
Commercial	37%	35.54	109.23	22.37	23.24	24.74
Industrial	26%	20.51	32.53	11.59	23.24	58.65
	Weighted Average $/kWh	19.25	49.96	12.54	15.78	25.08
	Average $/kWh	24.52				
	Average $/kWh excluding the 2009 DOE Study	18.16				

M. System Capacity Carrying Costs

The study assumes that the cheapest marginal resource is utilized to calculate the carrying cost of additional capacity. The cost of carrying incremental reserves was based on the capital and FOM of a new simple cycle natural gas Combustion Turbine (CT) consistent with the Company's IRP assumptions. For the study, the cost of each additional kW of reserves can be found in Confidential Appendix Table CA6. The additional CT units were forced to have a 5% EFOR in the simulations and used to vary reserve margin in the study.

IV. Simulation Methodology

Since most reliability events are high impact, low probability events, a large number of scenarios must be considered. For DEC, SERVM utilized thirty-nine years of historical weather and load shapes, five points of economic load growth forecast error, and fifteen iterations of unit outage draws for each scenario to represent a distribution of realistic scenarios. The number of yearly simulation cases equals 39 weather years * 5 load forecast errors * 15 unit outage iterations = 2,925 total iterations for the Base Case. This Base Case, comprised of 2,925 total iterations, was re-run at different reserve margin levels by varying the amount of CT capacity.

A. Case Probabilities

An example of probabilities given for each case is shown in Table 10. Each weather year is given equal probability and each weather year is multiplied by the probability of each load forecast error point to calculate the case probability.

Table 10. Case Probability Example

Weather Year	Weather Year Probability (%)	Load multipliers Due to Load Economic Forecast Error (%)	Load Economic Forecast Error Probability (%)	Case Probability (%)
1980	2.56	95.8	10	0.256
1980	2.56	97.3	25	0.64
1980	2.56	100	40	1.024
1980	2.56	102	15	0.384
1980	2.56	103.1	10	0.256
1981	2.56	95.8	10	0.256
1981	2.56	97.3	25	0.64
1981	2.56	100	40	1.024
1981	2.56	102	15	0.384
1981	2.56	103.1	10	0.256
1982	2.56	95.8	10	0.256

1982	2.56	97.3	25	0.64
1982	2.56	100	40	1.024
1982	2.56	102	15	0.384
1982	2.56	103.1	10	0.256
...	...	...	...	...
...	...	...	...	...
2018	2.56	103.1	10	0.256
			Total	100

For this study, LOLE is defined in number of days per year and is calculated for each of the 195 load cases and weighted based on probability. When counting LOLE events, only one event is counted per day even if an event occurs early in the day and then again later in the day. Across the industry, the traditional 1 day in 10 year LOLE standard is defined as 0.1 LOLE. Additional reliability metrics calculated are Loss of Load Hours (LOLH) in hours per year, and Expected Unserved Energy (EUE) in MWh.

Total system energy costs are defined as the following for each region:

$$Production\ Costs\ (Fuel\ Burn + Variable\ O\&M) + \ Purchase\ Costs - Sales\ Revenue \\ + Loss\ of\ Reserves + \ Cost\ of\ Unserved\ Energy$$

These components are calculated for each case and weighted based on probability to calculate total system energy costs for each scenario simulated. Loss of Reserves costs recognize the additional risk of depleting operating reserves and are costed out at the ORDC curve when they occur. As shown in the results these costs are almost negligible. The cost of unserved energy is simply the MWh of load shed multiplied by the value of lost load. System capacity costs are calculated separately outside of the SERVM model using the economic carrying cost of a new CT.

B. Reserve Margin Definition

For this study, winter and summer reserve margins are defined as the following:

- (Resources – Demand) / Demand
    - Demand is 50/50 peak forecast
    - Demand response programs are included as resources and not subtracted from demand
    - Solar capacity is counted at 1% capacity credit for winter reserve margin calculations, 37% for summer reserve margin calculations, and the small amount of battery capacity was counted at 80%.

As previously noted, the Base Case was simulated at different reserve margin levels by varying the amount of CT capacity in order to evaluate the impact of reserves on LOLE. In order to achieve lower reserve margin levels, capacity needed to be removed. For DEC, the Allen coal units were removed since they are scheduled to retire shortly after 2024 along with other CT capacity to achieve lower reserve margin levels. Table 11 shows a comparison of winter and summer reserve margin levels for the Base Case. As an example, when the winter reserve margin is 16%, the resulting summer reserve margin is 17.6% due to the 2,578 MW of solar on the system which provides greater summer capacity contribution.

Table 11. Relationship Between Winter and Summer Reserve Margin Levels

Winter	10.0%	12.0%	14.0%	16.0%	18.0%	20.0%
Corresponding Summer	12.4%	14.2%	15.9%	17.6%	19.4%	21.1%

V. Physical Reliability Results

Table 12 shows LOLE by month across a range of reserve margin levels for the Island Case. The analysis shows all of the LOLE falls in the winter. To achieve reliability equivalent to the 1 day in 10 year standard (0.1 LOLE) in the Island scenario, a 22.5% winter reserve margin is required. This 22.5% reserve margin is required to cover the combined risks seen in load uncertainty, weather uncertainty, and generator performance for the DEC system. Given the significant solar on the system, the summer reserves are approximately 2% greater than winter reserves which results in essentially no reliability risk in the summer months when total LOLE is 0.1 days per year.

Table 12. Island Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
10.0%	12.4%	0.81	0.14	0.08	-	0.00	0.12	0.70	0.80	0.31	0.11	0.02	0.27	2.05	1.31	3.36
11.0%	13.3%	0.69	0.12	0.06	-	0.00	0.09	0.48	0.51	0.19	0.07	0.01	0.20	1.35	1.09	2.44
12.0%	14.2%	0.58	0.10	0.05	-	0.00	0.06	0.31	0.33	0.12	0.04	0.01	0.15	0.87	0.88	1.75
13.0%	15.0%	0.48	0.08	0.04	-	0.00	0.04	0.19	0.21	0.07	0.03	0.00	0.11	0.55	0.71	1.26
14.0%	15.9%	0.40	0.07	0.03	-	0.00	0.02	0.11	0.14	0.04	0.02	0.00	0.08	0.34	0.58	0.92
15.0%	16.8%	0.33	0.06	0.03	-	-	0.02	0.07	0.09	0.03	0.01	-	0.06	0.21	0.47	0.68
16.0%	17.6%	0.28	0.05	0.02	-	-	0.01	0.04	0.05	0.02	0.01	-	0.04	0.13	0.39	0.52
17.0%	18.5%	0.23	0.04	0.02	-	-	0.01	0.03	0.03	0.01	0.00	-	0.03	0.09	0.32	0.41
18.0%	19.4%	0.19	0.03	0.01	-	-	0.01	0.02	0.02	0.01	0.00	-	0.03	0.06	0.27	0.33
19.0%	20.2%	0.16	0.03	0.01	-	-	0.01	0.02	0.01	0.00	-	-	0.02	0.04	0.22	0.26
20.0%	21.1%	0.13	0.02	0.01	-	-	0.00	0.01	0.01	0.00	-	-	0.02	0.02	0.18	0.20
21.0%	22.0%	0.11	0.02	0.00	-	-	0.00	0.00	0.01	0.00	-	-	0.01	0.01	0.14	0.15
22.0%	22.8%	0.08	0.01	0.00	-	-	0.00	0.00	0.01	0.00	-	-	0.01	0.01	0.10	0.11
23.0%	23.7%	0.06	0.01	0.00	-	-	0.00	0.00	0.00	0.00	-	-	0.00	0.00	0.08	0.08
24.0%	24.6%	0.05	0.01	0.00	-	-	0.00	0.00	0.00	0.00	-	-	0.00	0.00	0.06	0.06

Table 13 shows LOLE by month across a range of reserve margin levels for the Base Case which assumes neighbor assistance. As in the Island scenario, all of the LOLE occurs in the winter when total LOLE is at 0.1 days per year showing the same increased risk in the winter. To achieve reliability equivalent to the 1 day in 10 year standard (0.1 LOLE) in this scenario that includes market assistance, a 16.00% winter reserve margin is required.

Table 13. Base Case Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
5.00%	8.11%	0.21	0.05	0.02	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.04	0.05	0.33	0.38
6.00%	8.97%	0.20	0.05	0.02	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.04	0.04	0.30	0.35
7.00%	9.84%	0.18	0.05	0.02	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.03	0.04	0.28	0.31
8.00%	10.71%	0.17	0.04	0.01	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.03	0.03	0.25	0.28
9.00%	11.57%	0.15	0.04	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.03	0.03	0.23	0.25
10.00%	12.44%	0.14	0.04	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.02	0.21	0.23
11.00%	13.31%	0.13	0.03	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.02	0.18	0.20
12.00%	14.18%	0.11	0.03	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.16	0.18
13.00%	15.04%	0.10	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.15	0.15
14.00%	15.91%	0.09	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.13	0.13
15.00%	16.78%	0.08	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.11	0.12
16.00%	17.64%	0.07	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.10	0.10
17.00%	18.51%	0.06	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08
18.00%	19.38%	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.07
19.00%	20.24%	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.06
20.00%	21.11%	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.05
21.00%	21.98%	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.04
22.00%	22.84%	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03

Table 14 shows LOLE and other physical reliability metrics by reserve margin for the Base Case simulations. Loss of Load Hours (LOLH) is expressed in hours per year and Expected Unserved Energy (EUE) is expressed in MWh. The table shows that an 8% reserve margin results in an LOLH of 0.69 hours per year. Thus, to achieve 2.4 hours per year, which is far less stringent than the 1 day in 10 year standard (1 event in 10 years), DEC would require a reserve margin less than 8%. Astrapé does not recommend targeting a standard that allows for 2.4 hours of firm load shed every year as essentially would expect a firm load shed during peak periods ever year. The hours per event can be calculated by dividing LOLH by LOLE. The firm load shed events last approximately 2-3 hours on average. As these reserve margins decrease and firm load shed events increase, it is expected that reliance on external assistance, depletion of contingency reserves, and more demand response calls will occur and increase the overall reliability risk on the system.

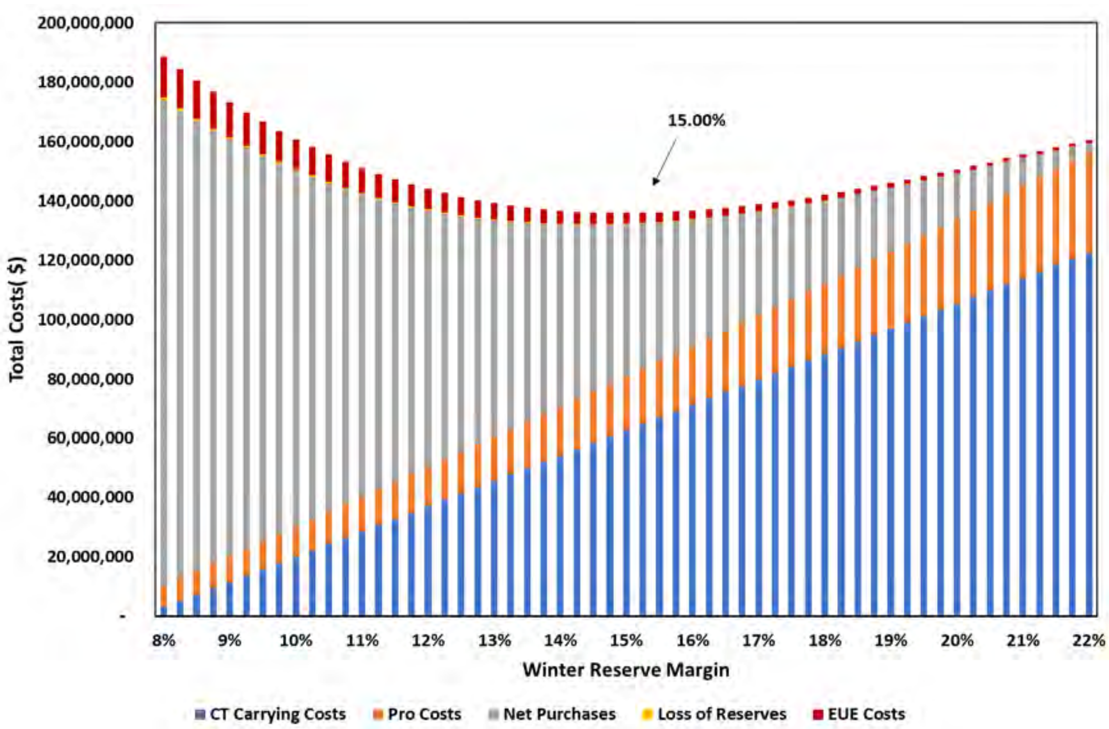
Table 14. Reliability Metrics: Base Case

Reserve Margin	LOLE	LOLH	EUE
%	**Days Per Year**	**Hours Per Year**	**MWh**
8.00%	0.28	0.69	748
8.50%	0.27	0.65	698
9.00%	0.25	0.61	650
9.50%	0.24	0.57	603
10.00%	0.23	0.54	559
10.50%	0.21	0.50	516
11.00%	0.20	0.47	475
11.50%	0.19	0.44	436
12.00%	0.18	0.41	399
12.50%	0.17	0.38	364
13.00%	0.16	0.35	330
13.50%	0.15	0.32	298
14.00%	0.14	0.29	268
14.50%	0.13	0.27	240
15.00%	0.12	0.25	214
15.50%	0.11	0.22	189
16.00%	0.10	0.20	167
16.50%	0.09	0.18	146
17.00%	0.08	0.17	127
17.50%	0.08	0.15	110
18.00%	0.07	0.13	94
18.50%	0.06	0.12	81
19.00%	0.06	0.11	69
19.50%	0.05	0.10	59
20.00%	0.05	0.09	51
20.50%	0.04	0.08	45
21.00%	0.04	0.07	40
21.50%	0.04	0.06	38
22.00%	0.03	0.06	37
22.50%	0.03	0.06	38
23.00%	0.03	0.05	41
23.50%	0.03	0.05	46
24.00%	0.02	0.05	52

VI. Base Case Economic Results

While Astrapé believes physical reliability metrics should be used for determining planning reserve margin because customers expect to have power during extreme weather conditions, customer costs provide additional information in resource adequacy studies. From a customer cost perspective, total system costs were analyzed across reserve margin levels for the Base Case. Figure 11 shows the risk neutral costs at the various winter reserve margin levels. This risk neutral represents the weighted average results of all weather years, load forecast uncertainty, and unit performance iterations at each reserve margin level and represents the expected value on a year in and year out basis.

Figure 11. Base Case Risk Neutral Economic Results[27]

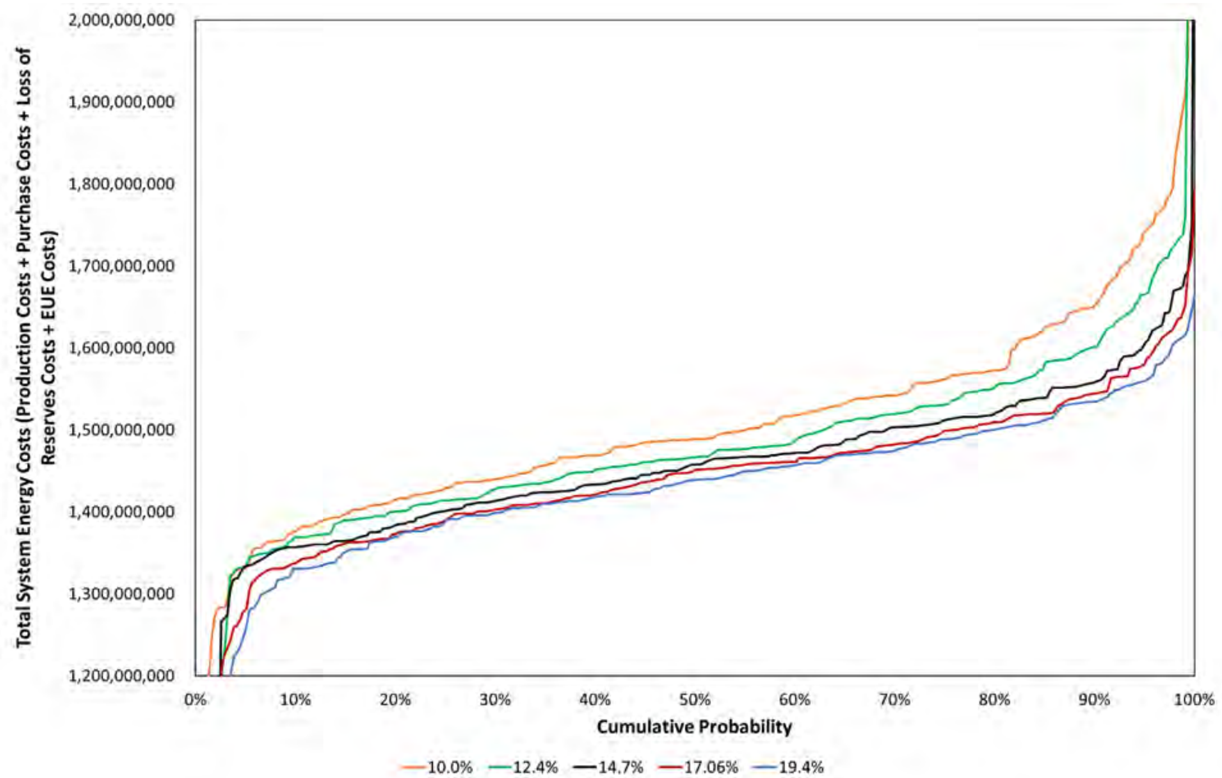


[27] Costs that are included in every reserve margin level have been removed so the reader can see the incremental impact of each category of costs. DEC has approximately 1.5 billion dollars in total costs.

As Figure 11 shows, the lowest risk neutral cost falls at a 15.00% reserve margin very close to the one day in 10-year standard (LOLE of 0.1). These values are close because the summer reserve margins are only slightly higher than the winter reserve margins which increases the savings of adding additional CT capacity. The majority of the savings seen in adding additional capacity is recognized in the winter.[28] The cost curve is fairly flat for a large portion of the reserve margin curve because when CT capacity is added there is always system energy cost savings from either reduction in loss of load events, savings in purchases, or savings in production costs. This risk neutral scenario represents the weighted average of all scenarios but does not illustrate the impact of high-risk scenarios that could cause customer rates to be volatile from year to year. Figure 12, however, shows the distribution of system energy costs (production costs, purchase costs, loss of reserves costs, and the costs of EUE) at different reserve margin levels. This figure excludes fixed CT costs which increase with reserve margin level. As reserves are added, system energy costs decline. By moving from lower reserve margins to higher reserve margins, the volatile right side of the curve (greater than 85% Cumulative Probability) is dampened, shielding customers from extreme scenarios for relatively small increases in annual expected costs. By paying for additional CT capacity, extreme scenarios are mitigated.

[28] As the DEC study shows, the lower DEC summer reserve margins increase the risk neutral economic reserve margin level compared to the DEP Study.

Figure 12. Cumulative Probability Curves



The next table shows the same data laid out in tabular format. It includes the weighted average results as shown in Figure 11 as well as the energy savings at higher cumulative probability levels. As shown in the table, going from the risk neutral reserve margin of 15% to 17% increases customer costs on average by $2.9 million a year[29] and reduces LOLE from 0.12 to 0.08 events per year. The LOLE for the island scenario decreases from 0.68 days per year to 0.41 days per year. However, 10% of the time energy savings are greater than or equal to $21 million if a 17% reserve margin is maintained versus the 15% reserve margin. And 5 % of the time, $34 million or more is saved.

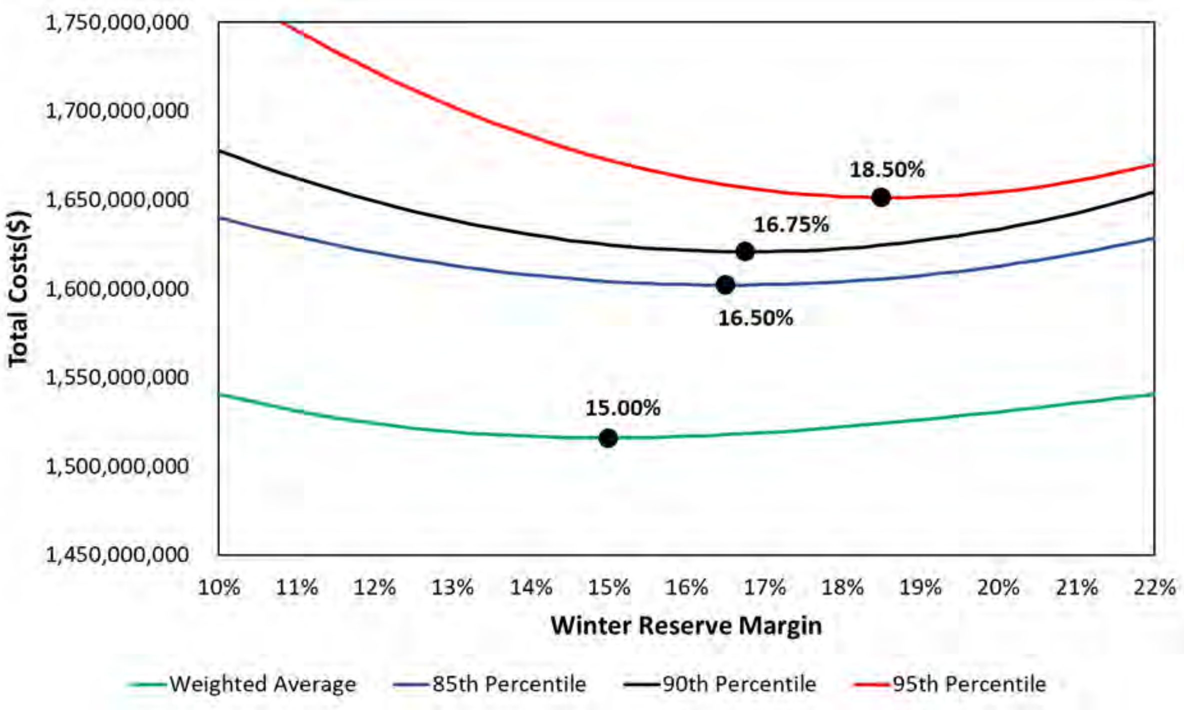
[29] This includes $17 million for CT costs and $14 million of system energy savings.

Table 15. Annual Customer Costs vs LOLE

Reserve Margin	Change in Capital Costs ($M)	Change in Energy Costs ($M)	Total Weighted Average Costs ($M)	85th Percentile Change in Energy Costs ($M)	90th Percentile Change in Energy Costs ($M)	95th Percentile Change in Energy Costs ($M)	LOLE (Days Per Year)	LOLE (Days Per Year) Island Sensitivity
15.00%	-	-	-	-	-	-	0.12	0.68
16.00%	8.5	-7.8	0.8	-10.0	-11.7	-18.6	0.1	0.52
17.00%	17.1	-14.2	2.9	-19.0	-21.0	-34.0	0.08	0.41
18.00%	25.6	-19.5	6.1	-25.8	-27.8	-46.1	0.07	0.33
19.00%	34.2	-24.0	10.1	-30.8	-32.1	-55.0	0.06	0.26
20.00%	42.7	-28.0	14.7	-34.1	-33.9	-60.6	0.05	0.20

The next figure takes the 85th, 90th, and 95th percentile points of the total system energy costs in Figure 12 and adds them to the fixed CT costs at each reserve margin level. It is rational to view the data this way because CT costs are more known with a small band of uncertainty while the system energy costs are volatile as shown in the previous figure. In order to attempt to put the fixed costs and the system energy costs on a similar basis in regards to uncertainty, higher cumulative probability points using the 85th – 95th percentile range can be considered for the system energy costs. While the risk neutral lowest cost curve falls at 15% reserve margin, the 85th to 95th percentile cost curves point to a 16-19% reserve margin.

Figure 13. Total System Costs by Reserve Margin



Carrying additional capacity above the risk neutral reserve margin level to reduce the frequency of firm load shed events in DEC is similar to the way PJM incorporates its capacity market to maintain the one day in 10-year standard (LOLE of 0.1). In order to maintain reserve margins that meet the one day in 10-year standard (LOLE of 0.1), PJM supplies additional revenues to generators through its capacity market. These additional generator revenues are paid by customers who in turn see enhanced system reliability and lower energy costs. At much lower reserve margin levels, generators can recover fixed costs in the market due to capacity shortages and more frequent high prices seen during these periods, but the one day in 10-year standard (LOLE of 0.1) target is not satisfied.

VII. Sensitivities

Several sensitivities were simulated in order to understand the effects of different assumptions on the 0.1 LOLE minimum winter reserve margin and to address questions and requests from stakeholders.

Outage Sensitivities

As previously noted, the Base Case included a total of 400 MW of cold weather outages between DEC and DEP below ten degrees Fahrenheit based on outage data for the period 2016-2019. Sensitivities were run to see the effect of two cold weather outage assumptions. The first assumed that the 400 MW of total outages between DEC and DEP below ten degrees Fahrenheit were removed. As Table 16 indicates, the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) is lowered by 1.25% from the Base Case to 14.75%. This shows that if the Company was able to eliminate all cold weather outage risk, it could carry up to a 1.25% lower reserve margin. However, Astrapé recognizes based on North American Electric Reliability Corporation (NERC) documentation across the industry[30] that outages during cold temperatures could be substantially more than the 400 MW being applied at less than 10 degrees in this modeling.

30
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20WRA%202019_2020.pdfvv (page 5)

https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf

(beginning page 43)

Table 16. No Cold Weather Outage Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
No Cold Weather Outages	14.75%	14.75%	16.75%

The second outage sensitivity showed what the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) would need to be if cold weather outages were based solely on 2014-2019 historical data which increased the total MW of outages from 400 MW to 800 MW. Table 17 shows that the minimum reserve margin for 0.1 LOLE is 17.25 %.

Table 17. Cold Weather Outages Based on 2014-2019 Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Cold Weather Outages Based on 2014 - 2019	17.25%	15.00%	17.00%

Load Forecast Error Sensitivities

These sensitivities were run to see the effects of the Load Forecast Error (LFE) assumptions. In response to stakeholder feedback, an asymmetric LFE distribution was adopted in the Base Case which reflected a higher probability weighting on over-forecasting scenarios. In the first sensitivity, the LFE uncertainty was completely removed. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) increased by 0.25% to 16.25%. This demonstrates that the load forecast error assumed in the Base Case was reducing the target reserve margin levels since over-forecasting was more heavily weighted in the LFE distribution. Because of this result, Astrapé did not simulate additional sensitivities such as 2-year, 3-year, or 5-year LFE distributions.

Table 18. Remove LFE Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Remove LFE	16.25%	15.00%	16.00%

The second sensitivity removed the asymmetric Base Case distribution and replaced it with the originally proposed normal distribution. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) increased by 1.0% to 17.0%.

Table 19. Originally Proposed LFE Distribution Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Originally Proposed Normal Distribution	17.00%	16.00%	18.00%

Solar Sensitivities

The Base Case for DEC assumed that there was 2,578 MW of solar on the system. The first solar sensitivity decreased this number to 1,626 MW. This change in solar had no impact on the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) as the results in Table 20 show because the capacity contribution of solar in the winter reserve margin calculation is 1%.

Table 20. Low Solar Results

	LOLE	Economics	
Sensitivity	1 in 10	Weighted Average (risk neutral)	90th %
Base Case	16.00%	15.00%	16.75%
Low Solar	16.00%	16.00%	18.25%

The second solar sensitivity increased the amount of solar on the DEC system to 3,752 MW. This increase also had very little impact on the minimum reserve margins as Table 21 indicates. Both of these results are expected as solar provides almost no capacity value in the winter.

Table 21. High Solar Results

	LOLE	Economics	
Sensitivity	1 in 10	Weighted Average (risk neutral)	90th %
Base Case	16.00%	15.00%	16.75%
High Solar	15.75%	14.00%	14.50%

Demand Response (DR) Sensitivity

In this scenario, the winter demand response is increased to 1,122 MW to match the summer capacity. It is important to note that DR is counted as a resource in the reserve margin calculation similar to a conventional generator. Simply increasing DR to 1,122 MW results in a higher reserve margin and lower LOLE compared to the Base Case. Thus, CT capacity was adjusted (lowered) in the high DR sensitivity to maintain the same reserve margin level. Results showed that the 0.1 LOLE minimum reserve margin actually increased from 16.00% to 16.75% due to demand response's dispatch limits compared to a fully dispatchable traditional resource. DR may be an economic alternative to installing CT capacity, depending on market potential and cost. However, it should be noted that while Duke counts DR and conventional capacity as equivalent in load carrying capability in its IRP planning, the sensitivity results show that DR may have a slightly lower equivalent load carrying capability especially for programs with strict operational limits. The results are listed in Table 22 below.

Table 22. Demand Response Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Demand Response Winter as High as Summer	16.75%	18.25%	19.50%

No Coal Sensitivity

In this scenario, all coal units were replaced with CC/CT units. The CC units were modeled with a 4% EFOR and the CT units were modeled with a 5% EFOR. Due to the high EFOR's of the DEC coal units, the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) decreased slightly as shown in Table 23 below.

Table 23. No Coal Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Retire all Coal	15.25%	17.00%	20.25%

Climate Change Sensitivity

In this scenario, the loads were adjusted to reflect the temperature increase outlined in the National Oceanic and Atmospheric Administration (NOAA) Climate Change Analysis[31]. Based on NOAA's research, temperatures since 1981 have increased at an average rate of 0.32 degrees Fahrenheit per decade. Each synthetic load shape was increased to reflect the increase in temperature it would see to meet the 2024 Study Year. For example, 1980 has a 1.4 degree increase ($0.32 \frac{°F}{Decade} * \frac{1\,Decade}{10\,Year} * 44\,Years$). After the loads were adjusted, the analysis was rerun. The summer peaks saw an increase and the winter peaks especially in earlier weather years saw a decrease. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) is reduced to 16.00% from 15.75% in the Base Case under these assumptions. The results are listed in the table below.

Table 24. Climate Change Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Climate Change	15.75%	14.25%	16.75%

31 https://www.climate.gov/news-features/understanding-climate/climate-change-global-temperature

VIII. Economic Sensitivities

Table 25 shows the economic results if the cost of unserved energy is varied from $5,000/MWh to $25,000/MWh and the cost of incremental capacity is varied from $40/kW-yr to $60/kW-yr. As CT costs decrease, the economic reserve margin increases and as CT costs increase, the economic reserve margin decreases. The opposite occurs with the cost of EUE. The higher the cost of EUE, the higher the economic target.

Table 25. Economic Sensitivities

	Economics	
Sensitivity	**Weighted Average (risk neutral)**	**90th %**
Base Case	15.00%	16.75%
CT costs $40kW-yr	16.00%	17.25%
CT costs $60/kW-yr	13.75%	16.00%
EUE 5,000 $/MWh	14.50%	16.25%
EUE 25,000 $/MWh	15.25%	16.75%

IX. DEC/DEP Combined Sensitivity

A set of sensitivities was performed which assumed DEC, DEP-E, and DEP-W were dispatched together and all reserves were calculated as a single company across the three regions. In these scenarios, all resources down to the firm load shed point can be utilized to assist each other and there is a priority in assisting each other before assisting an outside neighbor. The following three scenarios were simulated for the Combined Case and their results are listed in the table below:

1) Combined-Base

2) Combined Target 1,500 MW Import Limit- This scenario assumed a maximum import limit from external regions into the sister utilities of 1,500 MW[32].

3) Combined-Remove LFE

As shown in the table below, the combined target scenario yielded a 0.1 LOLE reserve margin of 16.75% (based on DEC and DEP coincident peak).

Table 26. Combined Case Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**weighted avg (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Combined Target	16.75%	17.00%	17.75%
Combined Target 1,500 MW Import Limit	18.00%	17.25%	18.25%
Combined Target - Remove LFE	17.25%	17.00%	18.25%

[32] 1,500 MW represents approximately 4.7% of the total reserve margin requirement which is still less constrained than the PJM and MISO assumptions noted earlier.

X. Conclusions

Based on the physical reliability results of the Island, Base Case, Combined Case, additional sensitivities, as well as the results of the separate DEP Study, Astrapé recommends that DEC continue to maintain a minimum 17% reserve margin for IRP purposes. This reserve margin ensures reasonable reliability for customers. Astrapé recognizes that a standalone DEC utility would require a 22.5% reserve margin to meet the one day in 10-year standard (LOLE of 0.1) and even with market assistance, DEC would need to maintain a 16.00% reserve margin. However, given the combined DEC and DEP sensitivity resulting in a 16.75% reserve margin, and the 19.25% reserve margin required by DEP to meet the one day in 10-year standard (LOLE of 0.1), Astrapé believes the 17% reserve margin as a minimum target is still reasonable for planning purposes. Since the sensitivity results removing all economic load forecast uncertainty increases the reserve margin to meet the 1 day in 10-year standard, Astrapé believes this 17% minimum reserve margin should be used in the short- and long-term planning process.

To be clear, even with 17% reserves, this does not mean that DEC will never be forced to shed firm load during extreme conditions as DEC and its neighbors shift to reliance on intermittent and energy limited resources such as storage and demand response. DEC has had several events in the past few years where actual operating reserves were close to being exhausted even with higher than 17% planning reserve margins. If not for non-firm external assistance which this study considers, firm load would have been shed. In addition, it is not possible to capture all tail end risk that could occur from a reliability perspective. Astrapé's approach has been to model the system's risks around weather, load, generator performance, and market assistance as accurately as possible without overly conservative assumptions. Based on all results, Astrapé believes planning to a 17% reserve margin is prudent from a physical reliability perspective and for small increases in costs above the risk-neutral 15% reserve margin level, customers will experience enhanced reliability and less rate volatility.

As the DEC resource portfolio changes with the addition of more intermittent resources and energy limited resources, the 17% minimum reserve margin is sufficient as long as the Company has accounted for the capacity value of solar and battery resources which changes as a function of penetration. DEC should also monitor changes in the IRPs of neighboring utilities and the potential impact on market assistance. Unless DEC observes seasonal risk shifting back to summer, the 17% reserve margin should be reasonable but should be re-evaluated as appropriate in future IRPs and future reliability studies. To ensure summer reliability is maintained, Astrapé recommends not allowing the summer reserve margin to drop below 15%.[33]

[33] Currently, if a winter target is maintained at 17%, summer reserves will be above 15%.

XI. Appendix A

Table A.1 Base Case Assumptions and Sensitivities

Assumption	Base Case Value	Sensitivity	Comments
Weather Years	1980-2018		Based on the historical data, the 1980 - 2018 period aligns well with the last 100 years. Shorter time periods do not capture the distribution of extreme days seen in history.
Synthetic Loads and Load Shapes	As Documented in 2-21-20 Presentation	Impact of Climate Change on synthetic load shapes and peak load forecast	Note: This is a rather complex sensitivity and the ability to capture the impact of climate change may be difficult. We would appreciate input and suggestions from other parties on developing an approach to capture the potential impacts of climate change on resource adequacy planning.
LFE	Use an asymmetrical distribution. Use full LFE impact in years 4 and beyond. Recognize reduced LFE impacts in years 1-3.	1,2,3,5 year ahead forecast error	
Unit Outages	As Documented in 2-21-20 Presentation		
Cold Weather Outages	Moderate Cold Weather Outages: Capture Incremental Outages at temps less than 10 degrees based on the 2016 - 2018 dataset (~400 MW total across the DEC and DEP for all temperature below 10 degree. This will be applied on a peak load ratio basis) For Neighboring regions, the same ratio of cold weather outages to peak load will be applied.	2 Sensitivities: (1) Remove cold weather outages (2) Include cold weather outages based on 2014 -2018 dataset	The DEC and DEP historical data shows that during extreme cold temperatures it is likely to experience an increase in generator forced outages; this is consistent with NERC's research across the industry. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20WRA%202019_2020.pdf - page 5 https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf - beginning on pg 43
Hydro/Pumped Storage	As Documented in 2-21-20 Presentation		
Solar	As Documented in 2-21-20 Presentation		
Demand Response	As Documented in 2-21-20 Presentation	Sensitivity increasing winter DR	
Neighbor Assistance	As Documented in 2-21-20 Presentation	Island Sensitivity	Provide summary of market assistance during EUE hours; transmission versus capacity limited.
Operating Reserves	As Documented in 2-21-20 Presentation		
CT costs/ORDC/VOLL	As Documented in 2-21-20 Presentation	Low and High Sensitivities for each	
Study Topology	Determine separate DEC and DEP reserve margin targets	Combined DEC/DEP target	A simulation will be performed which assumes DEC, DEP-E and DEP-W are dispatched together and reserves are calculated as a single company across the three regions.

XII. Appendix B

Table B.1 Percentage of Loss of Load by Month and Hour of Day for the Base Case

	Month											
Hour of Day	1	2	3	4	5	6	7	8	9	10	11	12
1	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	0.16%	0.16%	-	-	-	-	-	-	-	-	-	-
5	0.98%	0.49%	-	-	-	-	-	-	-	-	-	-
6	4.43%	1.48%	-	-	-	-	-	-	-	-	-	-
7	16.56%	5.74%	-	-	-	-	-	-	-	-	-	0.33%
8	32.79%	7.87%	-	-	-	-	-	-	-	-	-	2.62%
9	15.57%	0.82%	-	-	-	-	-	-	-	-	-	0.16%
10	4.43%	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	0.16%	-	-	-	-
18	-	-	-	-	-	-	0.33%	0.98%	-	-	-	-
19	-	-	-	-	-	-	0.49%	1.15%	-	-	-	-
20	-	-	-	-	-	-	0.16%	0.33%	-	-	-	-
21	-	-	-	-	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-	-	-	-
23	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-
Sum	74.92%	16.56%	1.80%	-	-	-	0.98%	2.62%	-	-	-	3.11%

ASTRAPÉ CONSULTING
innovation in electric system planning

Duke Energy Progress

2020 Resource Adequacy Study

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Contents

Executive Summary

This study was performed by Astrapé Consulting at the request of Duke Energy Progress (DEP) as an update to the study performed in 2016. The primary purpose of this study is to provide Duke system planners with information on physical reliability and costs that could be expected with various reserve margin[1] planning targets. Physical reliability refers to the frequency of firm load shed events and is calculated using Loss of Load Expectation (LOLE). The one day in 10-year standard (LOLE of 0.1) is interpreted as one day with one or more hours of firm load shed every 10 years due to a shortage of generating capacity and is used across the industry[2] to set minimum target reserve margin levels. Astrapé determined the reserve margin required to meet the one day in 10-year standard for the Base Case and multiple sensitivities included in the study. The study includes a Confidential Appendix containing confidential information such as fuel costs, outage rate data and transmission assumptions.

Customers expect to have electricity during all times of the year but especially during extreme weather conditions such as cold winter days when resource adequacy[3] is at risk for DEP[4] . In

[1] Throughout this report, winter and summer reserve margins are defined by the formula: (installed capacity - peak load) / peak load. Installed capacity includes capacity value for intermittent resources such as solar and energy limited resources such as battery.

[2] https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf; See Table 14 in A-1. PJM, MISO, NYISO ISO-NE, Quebec, IESO, FRCC, APS, NV Energy all use the 1 day in 10 year standard. As of this report, it is Astrapé's understanding that Southern Company has shifted to the greater of the economic reserve margin or the 1 day in 10 year standard.

[3] NERC RAPA Definition of "Adequacy" - The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components.

[4] Section (b)(4)(iv) of NCUC Rule R8-61 (Certificate of Public Convenience and Necessity for Construction of Electric Generation Facilities) requires the utility to provide "… a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area using information from the National Weather Service Automated Surface Observing System (ASOS) First Order Station in Asheville, Charlotte, Greensboro, Hatteras, Raleigh or Wilmington, depending upon the station that is located closest to where the plant will be located."

order to ensure reliability during these peak periods, DEP maintains a minimum reserve margin level to manage unexpected conditions including extreme weather, load growth, and significant forced outages. To understand this risk, a wide distribution of possible scenarios must be simulated at a range of reserve margins. To calculate physical reliability and customer costs for the DEP system, Astrapé Consulting utilized a reliability model called SERVM (Strategic Energy and Risk Valuation Model) to perform thousands of hourly simulations for the 2024 study year at various reserve margin levels. Each of the yearly simulations was developed through a combination of deterministic and stochastic modeling of the uncertainty of weather, economic growth, unit availability, and neighbor assistance.

In the 2016 study, reliability risk was concentrated in the winter and the study determined that a 17.5% reserve margin was required to meet the one day in 10-year standard (LOLE of 0.1), for DEP. Because DEP's sister utility DEC required a 16.5% reserve margin to meet the same reliability standard, Duke Energy averaged the studies and used a 17% planning reserve margin target for both companies in its Integrated Resource Plan (IRP). This 2020 Study updates all input assumptions to reassess resource adequacy. As part of the update, several stakeholder meetings occurred to discuss inputs, methodology, and results. These stakeholder meetings included representatives from the North Carolina Public Staff, the South Carolina Office of Regulatory Staff (ORS), and the North Carolina Attorney General's Office. Following the initial meeting with stakeholders on February 21, 2020, the parties agreed to the key assumptions and sensitivities listed in Appendix A, Table A.1.

Preliminary results were presented to the stakeholders on May 8, 2020 and additional follow up was done throughout the month of May. Moving from the 2016 Study, the Study Year was shifted from 2019 to 2024 and assumed solar capacity was updated to the most recent projections. Because solar projections increased, LOLE has continued to shift from the summer to the winter. The high volatility in peak winter loads seen in the 2016 Study remained evident in recent historical data. In response to stakeholder feedback, the four year ahead economic load forecast error was dampened by providing a higher probability weighting on over-forecasting scenarios relative to under-forecasting scenarios. The net effect of the new distribution is to slightly reduce the target reserve margin compared to the previous distribution supplying slight upward pressure on the target reserve margin. This means that if the target reserve margin from this study is adopted, no reserves would be held for potential under-forecast of load growth. Generator outages remained in line with 2016 expectations, but additional cold weather outages of 140 MW for DEP were included for temperatures less than 10 degrees.

Physical Reliability Results-Island

Table ES1 shows the monthly contribution of LOLE at various reserve margin levels for the Island scenario. In this scenario, it is assumed that DEP is responsible for its own load and that there is no assistance from neighboring utilities. The summer and winter reserve margins differ for all scenarios due to seasonal demand forecast differences, weather-related thermal generation capacity differences, demand response seasonal availability, and seasonal solar capacity value. Using the one day in 10-year standard (LOLE of 0.1), which is used across the industry to set minimum target reserve margin levels, DEP would require a 25.5% winter reserve margin in the Island Case where no assistance from neighboring systems was assumed.

Given the significant level of solar on the system, the summer reserves are approximately 12% greater than winter reserves which results in no reliability risk in the summer months. This 25.5% reserve margin is required to cover the combined risks seen in load uncertainty, weather uncertainty, and generator performance for the DEP system. As discussed below, when compared to Base Case results which recognizes neighbor assistance, results of the Island Case illustrate both the benefits and risks of carrying lower reserve margins through reliance on neighboring systems.

Table ES1. Island Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
10.0%	22.3%	0.43	0.09	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.70	0.71
11.0%	23.2%	0.37	0.08	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.61	0.62
12.0%	24.2%	0.32	0.07	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.53	0.54
13.0%	25.2%	0.28	0.06	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.47	0.47
14.0%	26.2%	0.25	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.41	0.41
15.0%	27.2%	0.21	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.35	0.36
16.0%	28.2%	0.19	0.05	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.31	0.31
17.0%	29.1%	0.17	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.28	0.28
18.0%	30.1%	0.15	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.25	0.25
19.0%	31.1%	0.13	0.04	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.22	0.22
20.0%	32.1%	0.12	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.20	0.20
21.0%	33.1%	0.11	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.18	0.18
22.0%	34.1%	0.10	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.16	0.16
23.0%	35.1%	0.09	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.14	0.14
24.0%	36.0%	0.08	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.12	0.12
25.0%	37.0%	0.07	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.11	0.11
26.0%	38.0%	0.06	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.10	0.10

Physical Reliability Results-Base Case

Astrapé recognizes that DEP is part of the larger eastern interconnection and models neighbors one tie away to allow for market assistance during peak load periods. However, it is important to also understand that there is risk in relying on neighboring capacity that is less dependable than owned or contracted generation in which DEP would have first call rights. While there are certainly advantages of being interconnected due to weather diversity and generator outage diversity across regions, market assistance is not guaranteed and Astrapé believes Duke Energy has taken a moderate to aggressive approach (i.e. taking significant credit for neighboring regions) to modeling neighboring assistance compared to other surrounding entities such as PJM Interconnection L.L.C. (PJM)[5] and the Midcontinent Independent System Operator (MISO)[6]. A full description of the market assistance modeling and topology is available in the body of the report. Table ES2 shows the monthly LOLE at various reserve margin levels for the Base Case scenario which is the Island scenario with neighbor assistance included[7].

[5] PJM limits market assistance to 3,500 MW which represents approximately 2.3% of its reserve margin compared to 6.25% assumed for DEP. https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20191008/20191008-pjm-reserve-requirement-study-draft-2019.ashx – page 11
[6]MISO limits external assistance to a Unforced Capacity (UCAP) of 2,331 MW which represents approximately 1.8% of its reserve margin compared to 6.25% assumed for DEP. https://www.misoenergy.org/api/documents/getbymediaid/80578 page 24 (copy and paste link in browser)
[7] Reference Appendix B, Table B.1 for percentage of loss of load by month and hour of day for the Base Case.

Table ES2. Base Case Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
10.0%	22.3%	0.14	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.23	0.23
11.0%	23.2%	0.13	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.21	0.21
12.0%	24.2%	0.12	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.19	0.19
13.0%	25.2%	0.11	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.18	0.18
14.0%	26.2%	0.10	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.16	0.16
15.0%	27.2%	0.09	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.15	0.15
16.0%	28.2%	0.08	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.13	0.13
17.0%	29.1%	0.07	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.12	0.12
18.0%	30.1%	0.07	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.11	0.11
19.0%	31.1%	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.10	0.10
20.0%	32.1%	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
21.0%	33.1%	0.05	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
22.0%	34.1%	0.05	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08

As the table indicates, the required reserve margin to meet the one day in 10-year standard (LOLE of 0.1), is 19.25% which is 6.25% lower than the required reserve margin for 0.1 LOLE in the Island scenario. Approximately one fourth of the 25.5% required reserves is reduced due to interconnection ties. Astrapé also notes utilities around the country are continuing to retire and replace fossil-fuel resources with more intermittent or energy limited resources such as solar, wind, and battery capacity. For example, Dominion Energy Virginia has made substantial changes to its plans as this study was being conducted and plans to add substantial solar and other renewables to its system that could cause additional winter reliability stress than what is modeled. The below excerpt is from page 6 of Dominion Energy Virginia's 2020 IRP[8]:

> In the long term, based on current technology, other challenges will arise from the significant development of intermittent solar resources in all Alternative Plans. For example, based on the nature of solar resources, the Company will have excess capacity in the summer, but not enough capacity in the winter. Based on current technology, the Company would need to meet this winter deficit by either building additional energy storage resources or by buying capacity from the market. In addition, the Company would likely need to import a significant amount of energy during the winter, but would need to export or store significant amounts of energy during the spring and fall.

Additionally, PJM now considers the DOM Zone to be a winter peaking zone where winter peaks are projected to exceed summer peaks for the forecast period.[9] While this is only one example, these potential changes to surrounding resource mixes may lead to less confidence in market assistance for the future during early morning winter peak loads. Changes in neighboring system resource portfolios and load profiles will be an important consideration in future resource adequacy studies. To the extent historic diversification between DEP and neighboring systems declines, the historic reliability benefits DEP has experienced from being an interconnected system will also decline. It is worth nothing that after this study was completed, California experienced rolling blackouts during extreme weather conditions as the ability to rely on imported power has declined and has shifted away from dispatchable fossil-fuel resources and put greater reliance on intermittent resources.[10] It is premature to fully ascertain the lessons learned from the California load shed events. However, it does highlight the fact that as DEP reduces dependence on

[8] https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509
[9] Dominion Energy Virginia 2020 IRP, at 40.
[10] http://www.caiso.com/Documents/ISO-Stage-3-Emergency-Declaration-Lifted-Power-Restored-Statewide.pdf

dispatchable fossil fuels and increases dependence on intermittent resources, it is important to ensure it is done in a manner that does not impact reliability to customers.

Physical Reliability Results-DEP/DEC Combined Case

In addition to running the Island and Base Case scenarios, a DEP and DEC Combined Case scenario was simulated to see the reliability impact of DEP and DEC as a single balancing authority. In this scenario, DEC and DEP prioritize helping each other over their other external neighbors but also retain access to external market assistance. The various reserve margin levels are calculated as the total resources in both DEC and DEP using the combined coincident peak load, and reserve margins are increased together for the combined utilities. Table ES3 shows the results of the Combined Case which shows that a 16.75% combined reserve margin is needed to meet the 1 day in 10-year standard. An additional Combined Case sensitivity was simulated to assess the impact of a more constrained import limit. This scenario assumed a maximum import limit from external regions into the sister utilities of 1,500 MW[11] resulting in an increase in the reserve margin from 16.75% to 18.0%.

Table ES3. Combined Case Physical Reliability Results

Sensitivity	1 in 10 LOLE Reserve Margin
Base Case	19.25%
Combined Target	16.75%
Combined Target 1,500 MW Import Limit	18.00%

[11] 1,500 MW represents approximately 4.7% of the total reserve margin requirement which is still less constrained than the PJM and MISO assumptions noted earlier.

Results for the Combined Case and the individual Base Cases are outlined in the table below. The DEC results are documented in a separate report but show that a 16.0% reserve margin is required to meet the one day in 10-year standard (LOLE of 0.1).

Table ES4. Combined Case Differences

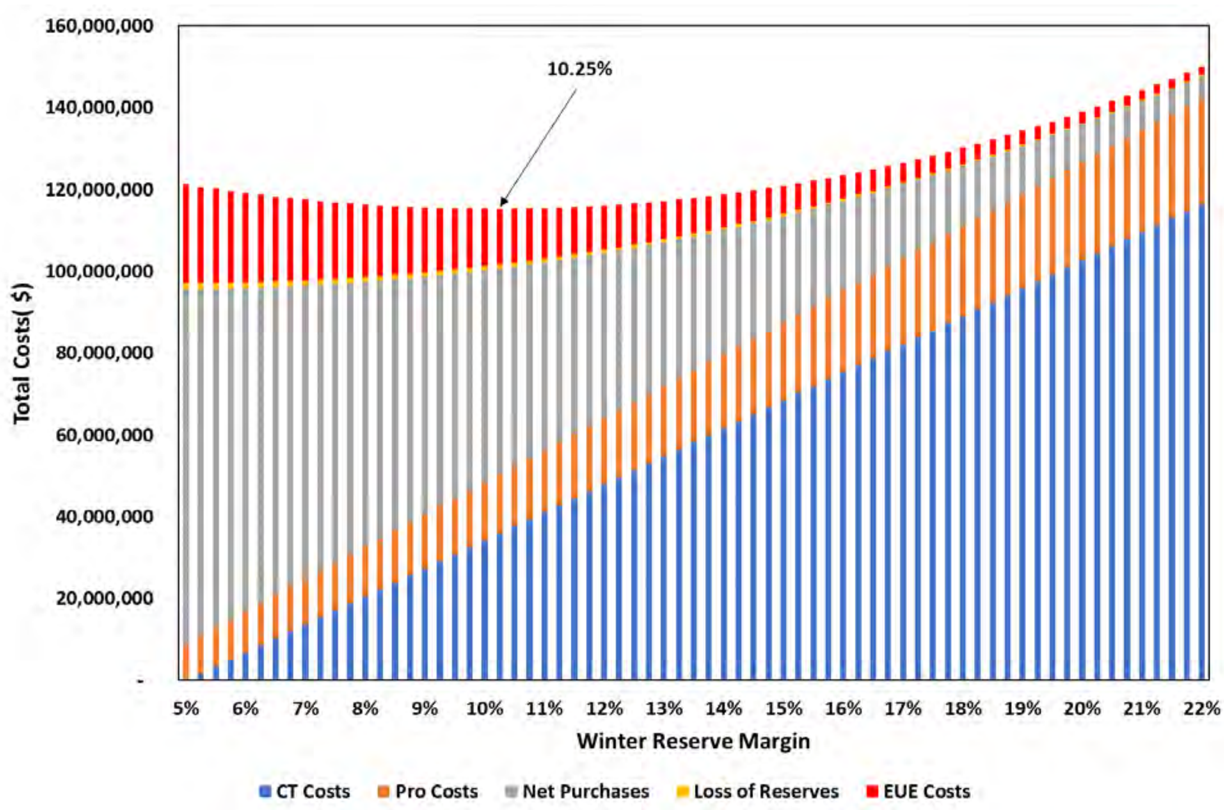
Region	1 in 10 LOLE Reserve Margin
DEC	16.00%
DEP	19.25%
Combined (Coincident)	16.75%

Economic Reliability Results

While Astrapé believes physical reliability metrics should be used for determining planning reserve margin because customers expect to have power during extreme weather conditions, customer costs provide additional information in resource adequacy studies. From a customer cost perspective, total system costs[12] were analyzed across reserve margin levels for the Base Case. Figure ES1 shows the risk neutral costs at the various winter reserve margin levels. This risk neutral represents the weighted average results of all weather years, load forecast uncertainty, and unit performance iterations at each reserve margin level and represents the yearly expected value on a year in and year out basis.

[12] System costs = system energy costs plus capacity costs of incremental reserves. System energy costs include production costs + net purchases + loss of reserves costs + unserved energy costs while system capacity costs include the fixed capital and fixed Operations and Maintenance (FOM) for CT capacity. Unserved energy costs equal the value of lost load times the expected unserved energy.

Figure ES1. Base Case Risk Neutral Economic Results[13]



As Figure ES1 shows, the lowest risk neutral cost falls at a 10.25% reserve margin. The reason this risk neutral reserve margin is significantly lower than 19.25% reserve margin required to meet the one day in 10-year standard (LOLE of 0.1) is due to high reserve margins in the summer. The majority of the economic benefit of additional capacity is recognized in the winter which generally has shorter duration high load periods.[14] The cost curve is fairly flat for a large portion of the reserve margin curve because when CT capacity is added there are system energy cost savings from either reduction in loss of load events, savings in purchases, or savings in production costs. This risk neutral scenario represents the weighted average of all scenarios but does not illustrate

[13] Costs that are included in every reserve margin level have been removed so the reader can see the incremental impact of each category of costs. DEP has approximately 1 billion dollars in total costs.
[14] As the DEC study shows, the lower DEC summer reserve margins increase the risk neutral economic reserve margin level compared to the DEP Study.

the impact of high-risk scenarios that could cause customer rates to be volatile from year to year. Figure ES2, however, shows the distribution of system energy costs which includes production costs, purchase costs, loss of reserves costs, and the costs of expected unserved energy (EUE) at different reserve margin levels. This figure excludes fixed CT costs which increase with reserve margin level. As reserves are added, system energy costs decline. By moving from lower reserve margins to higher reserve margins, the volatile right side of the curve (greater than 85% Cumulative Probability) is dampened, shielding customers from extreme scenarios for relatively small increases in annual expected costs. By paying for additional CT capacity, extreme scenarios are mitigated.

Figure ES2. System Energy Costs (Cumulative Probability Curves)

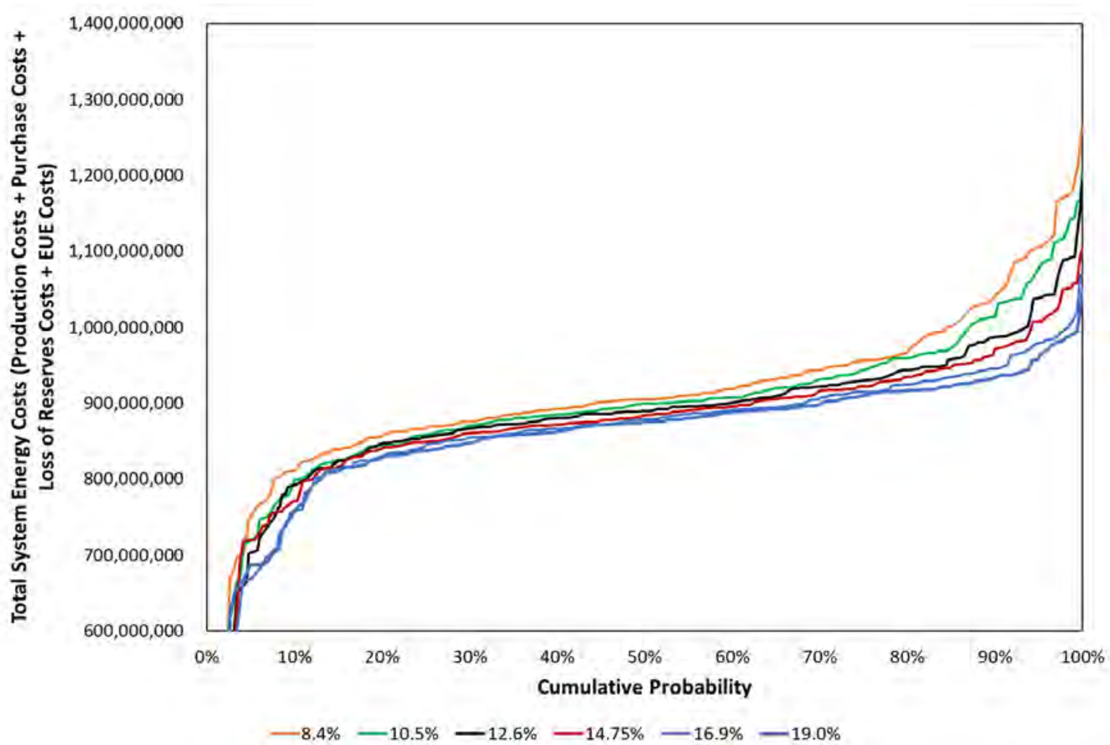


Table ES5 shows the same data laid out in tabular format. It includes the weighted average results as shown in Figure ES1 as well as the energy savings at higher cumulative probability levels from

Figure ES2. As shown in the table, going from the risk neutral reserve margin of 10.25% to 17%, customer costs on average increase by $11 million a year[15] and LOLE is reduced from 0.23 to 0.12 events per year. The LOLE for the island scenario decreases from 0.71 days per year to 0.28 days per year. However, 10% of the time energy savings are greater than or equal to $67 million if a 17% reserve margin is maintained versus the 10.25% reserve margin. While 5% of the time, $101 million or more is saved.

Table ES5. Annual Customer Costs vs LOLE

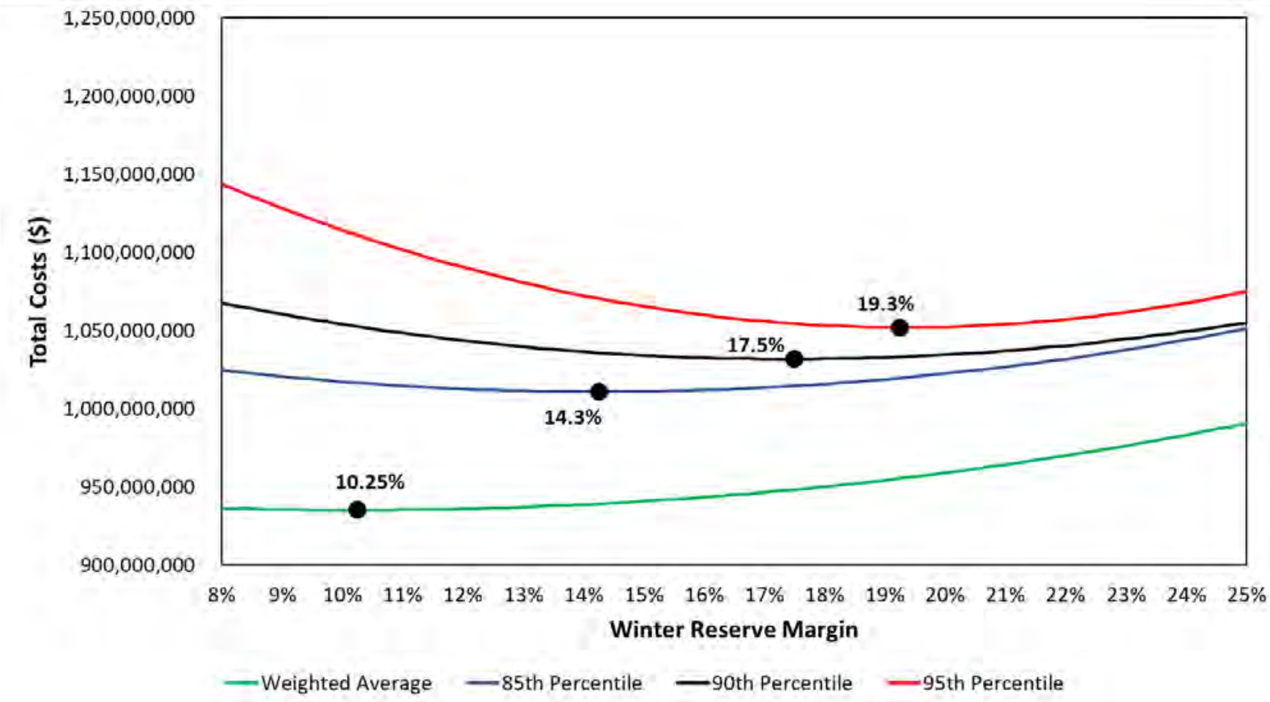
Reserve Margin	Change in Capital Costs ($M)	Change in Energy Costs ($M)	Total Weighted Average Costs ($M)	85th Percentile Change in Energy Costs ($M)	90th Percentile Change in Energy Costs ($M)	95th Percentile Change in Energy Costs ($M)	LOLE (Days Per Year)	LOLE (Days Per Year) Island Sensitivity
10.25%	-	-	-	-	-	-	0.23	0.71
11.00%	5.1	-5.0	0.2	-7.1	-9.3	-14.5	0.21	0.62
12.00%	12.0	-11.2	0.8	-15.9	-20.9	-32.5	0.19	0.54
13.00%	18.8	-16.9	1.9	-24.0	-31.8	-49.1	0.18	0.47
14.00%	25.7	-22.2	3.5	-31.4	-41.8	-64.3	0.16	0.41
15.00%	32.5	-26.9	5.6	-38.0	-51.0	-78.0	0.15	0.36
16.00%	39.4	-31.2	8.2	-44.0	-59.4	-90.3	0.13	0.31
17.00%	46.2	-34.9	11.3	-49.3	-67.0	-101.2	0.12	0.28
18.00%	53.1	-38.1	14.9	-53.9	-73.7	-110.7	0.11	0.25
19.00%	59.9	-40.8	19.1	-57.8	-79.7	-118.7	0.1	0.22
20.00%	66.7	-43.0	23.8	-61.0	-84.8	-125.3	0.09	0.2

The next figure takes the 85th, 90th, and 95th percentile points of the total system energy costs in Figure ES2 and adds them to the fixed CT costs at each reserve margin level. It is rational to view the data this way because CT costs are more known with a small band of uncertainty while the system energy costs are volatile as shown in the previous figure. In order to attempt to put the fixed costs and the system energy costs on a similar basis in regards to uncertainty, higher

[15] This includes $46 million for additional CT costs less $35 million of system energy savings.

cumulative probability points using the 85th – 95th percentile range can be considered for the system energy costs. While the risk neutral lowest cost curve falls at 10.25% reserve margin, the 85th to 95th percentile cost curves point to a 14-19% reserve margin.

Figure ES3. Total System Costs by Reserve Margin



Carrying additional capacity above the risk neutral reserve margin level to reduce the frequency of firm load shed events in DEP is similar to the way PJM incorporates its capacity market to maintain the one day in 10-year standard (LOLE of 0.1). In order to maintain reserve margins that meet the one day in 10-year standard (LOLE of 0.1), PJM supplies additional revenues to generators through its capacity market. These additional generator revenues are paid by customers who in turn see enhanced system reliability and lower energy costs. At much lower reserve margin levels, generators can recover fixed costs in the market due to capacity shortages and more frequent high prices seen during these periods, but the one day in 10-year standard (LOLE of 0.1) target is not satisfied.

Sensitivity Results

Various sensitivities were run in addition to the Base Case to examine the reliability and cost impact of different assumptions and scenarios. Table ES6 lists the various sensitivities and the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) as well as economic results of each. These include sensitivities around cold weather generator outages, load forecast error uncertainty, solar penetration, the cost of unserved energy, the cost of CT capacity, demand response, coal retirements, and climate change. Detailed explanations of each sensitivity are available in the body of the report. The target reserve margin to meet the one day in 10-year standard (LOLE of 0.1) ranged from 18.50% to 20.50% depending on the sensitivity simulated.

Table ES6. Sensitivity Results

Sensitivity	1 in 10 LOLE Reserve Margin	Economic Risk Neutral	Economic 90th Percentile
Base Case	19.25%	10.25%	17.50%
No Cold Weather Outages	18.50%	9.50%	16.25%
Cold Weather Outages based on 2014 - 2019	20.50%	10.50%	17.75%
Remove LFE	20.00%	10.50%	17.50%
Originally Proposed Normal Distribution	20.25%	11.25%	17.50%
Low Solar	19.25%	11.75%	17.50%
High Solar	19.00%	9.50%	16.75%
CT costs 40 $/kW-yr	19.25%	12.50%	18.75%
CT costs 60 $/kW-yr	19.25%	6.00%	15.25%
EUE 5,000 $/MWh	19.25%	7.00%	13.75%
EUE 25,000 $/MWh	19.25%	11.75%	19.25%
Demand Response Winter as High as Summer	20.00%	12.50%	18.50%
Retire all Coal	19.50%	11.25%	17.50%
Climate Change	18.50%	9.75%	16.25%

Recommendation

Based on the physical reliability results of the Island, Base Case, Combined Case, additional sensitivities, as well as the results of the separate DEC Study, Astrapé recommends that DEP continue to maintain a minimum 17% reserve margin for IRP purposes. This reserve margin ensures reasonable reliability for customers. Astrapé recognizes that a standalone DEP utility would require a 25.5% reserve margin to meet the one day in 10-year standard (LOLE of 0.1) and even with market assistance, DEP would need to maintain a 19.25% reserve margin. Customers expect electricity during extreme hot and cold weather conditions and maintaining a 17% reserve margin is estimated to provide an LOLE of 0.12 events per year which is slightly less reliable than the one day in 10-year standard (LOLE of 0.1). However, given the combined DEC and DEP sensitivity resulting in a 16.75% reserve margin, and the 16% reserve margin required by DEC to meet the one day in 10-year standard (LOLE of 0.1), Astrapé believes the 17% reserve margin as a minimum target is still reasonable for planning purposes. Since the sensitivity results removing all economic load forecast uncertainty increase the reserve margin to meet the 1 day in 10-year standard, Astrapé believes this 17% minimum reserve margin should be used in the short- and long-term planning process.

To be clear, even with 17% reserves, this does not mean that DEP will never be forced to shed firm load during extreme conditions as DEP and its neighbors shift to reliance on intermittent and energy limited resources such as storage and demand response. DEP has had several events in the past few years where actual operating reserves were close to being exhausted even with higher than 17% planning reserve margins. If not for non-firm external assistance, which this study considers, firm load would have been shed. In addition, incorporation of tail end reliability risk in modeling should be from statistically and historically defendable methods; not from including subjective risks that cannot be assigned probability. Astrapé's approach has been to model the system's risks around weather, load, generator performance, and market assistance as accurately as possible without overly conservative assumptions. Based on all results, Astrapé believes planning to a 17% reserve margin is prudent from a physical reliability perspective and for small increases in costs above the risk-neutral 10.25% reserve margin level, customers will experience enhanced reliability and less rate volatility.

As the DEP resource portfolio changes with the addition of more intermittent resources and energy limited resources, the 17% minimum reserve margin is sufficient as long as the Company has accounted for the capacity value of solar and battery resources which changes as a function of penetration. DEP should also monitor changes in the IRPs of neighboring utilities and the potential impact on market assistance. Unless DEP observes seasonal risk shifting back to summer, the 17% reserve margin should be reasonable but should be re-evaluated as appropriate in future IRPs and in future reliability studies. To ensure summer reliability is maintained, Astrapé recommends not allowing the summer reserve margin to drop below 15%.[16]

[16] Currently, if a winter target is maintained at 17%, summer reserves will be above 15%.

I. List of Figures

II. List of Tables

III. Input Assumptions

A. Study Year

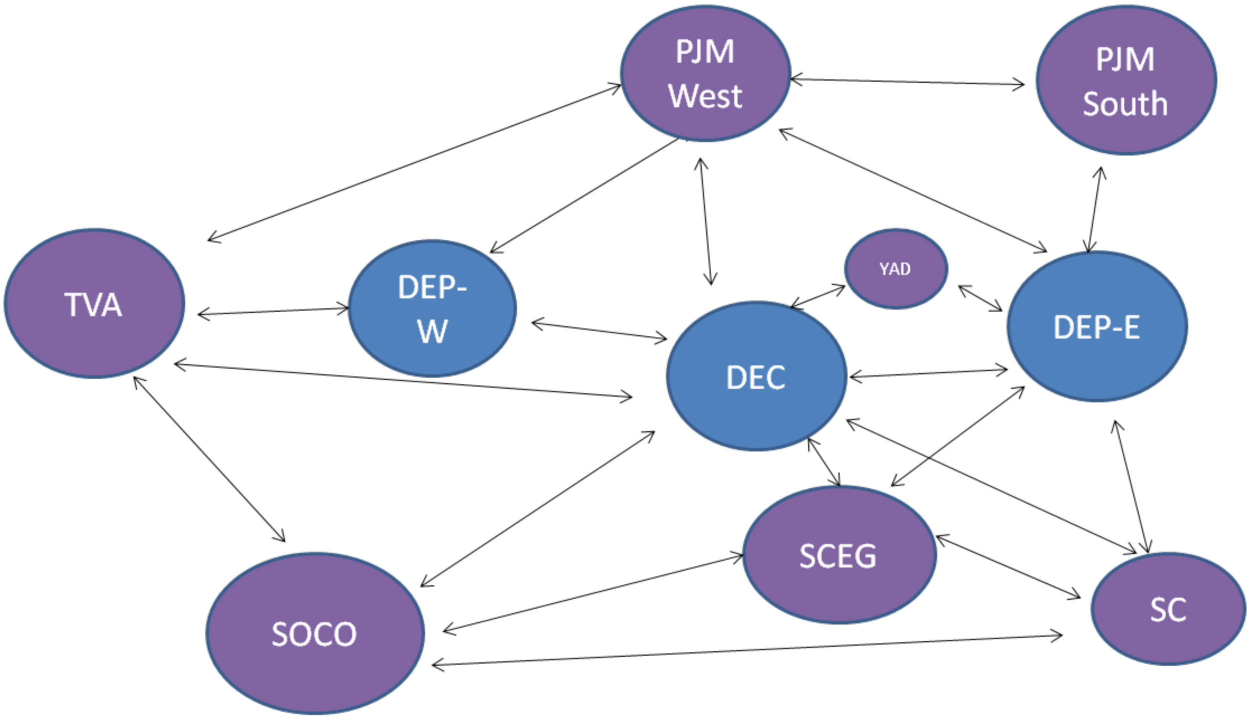
The selected study year is 2024[17]. The SERVM simulation results are broadly applicable to future years assuming that resource mixes and market structures do not change in a manner that shifts the reliability risk to a different season or different time of day.

B. Study Topology

Figure 1 shows the study topology that was used for the Resource Adequacy Study. DEP was modeled in two interconnect zones: (1) DEP – E and (2) DEP – W. While market assistance is not as dependable as resources that are utility owned or have firm contracts, Astrapé believes it is appropriate to capture the load diversity and generator outage diversity that DEP has with its neighbors. For this study, the DEP system was modeled with eight surrounding regions. The surrounding regions captured in the modeling included Duke Energy Carolinas (DEC), Tennessee Valley Authority (TVA), Southern Company (SOCO), PJM West & PJM South, Yadkin (YAD), Dominion Energy South Carolina (formally known as South Carolina Electric & Gas (SCEG)), and Santee Cooper (SC). SERVM uses a pipe and bubble representation in which energy can be shared based on economics but subject to transmission constraints.

[17] The year 2024 was chosen because it is four years into the future which is indicative of the amount of time needed to permit and construct a new generating facility.

Figure 1. Study Topology



Confidential Appendix Table CA1 displays the DEP import capability from surrounding regions including the amount set aside for Transmission Reliability Margin (TRM).

C. Load Modeling

Table 1 displays SERVM's modeled seasonal peak forecast net of energy efficiency programs for 2024.

Table 1. 2024 Forecast: DEP Seasonal Peak (MW)

	DEP-E Non-Coincident	DEP-W Non-Coincident	Combined Coincident
2024 Summer	12,227	879	13,042
2024 Winter	13,390	1,175	14,431

To model the effects of weather uncertainty, thirty-nine historical weather years (1980 - 2018) were developed to reflect the impact of weather on load. Based on the last five years of historical weather and load[18], a neural network program was used to develop relationships between weather observations and load. The historical weather consisted of hourly temperatures from five weather stations across the DEP service territory. The weather stations included Raleigh, NC, Wilmington, NC, Fayetteville, NC, Asheville, NC, and Columbia, SC. Other inputs into the neural net model consisted of hour of week, eight hour rolling average temperatures, twenty-four hour rolling average temperatures, and forty-eight hour rolling average temperatures. Different weather to load relationships were built for the summer, winter, and shoulder seasons. These relationships were then applied to the last thirty-nine years of weather to develop thirty-nine synthetic load shapes for 2024. Equal probabilities were given to each of the thirty-nine load shapes in the simulation. The synthetic load shapes were scaled to align the normal summer and winter peaks to the Company's projected thirty-year weather normal load forecast for 2024.

Figures 2 and 3 show the results of the 2014-2019 weather load modeling by displaying the peak load variance for both the summer and winter seasons. The y-axis represents the percentage

[18] The historical load included years 2014 through September of 2019.

deviation from the average peak. For example, the 1985 synthetic load shape would result in a summer peak load approximately 4.7% below normal and a winter peak load approximately 21.1% above normal. Thus, the bars represent the variance in projected peak loads based on weather experienced during the historic weather years. It should be noted that the variance for winter is much greater than summer. As an example, extreme cold temperatures can cause load to spike from additional electric strip heating. The highest summer temperatures typically are only a few degrees above the expected highest temperature and therefore do not produce as much peak load variation.

Figure 2. DEP Summer Peak Weather Variability

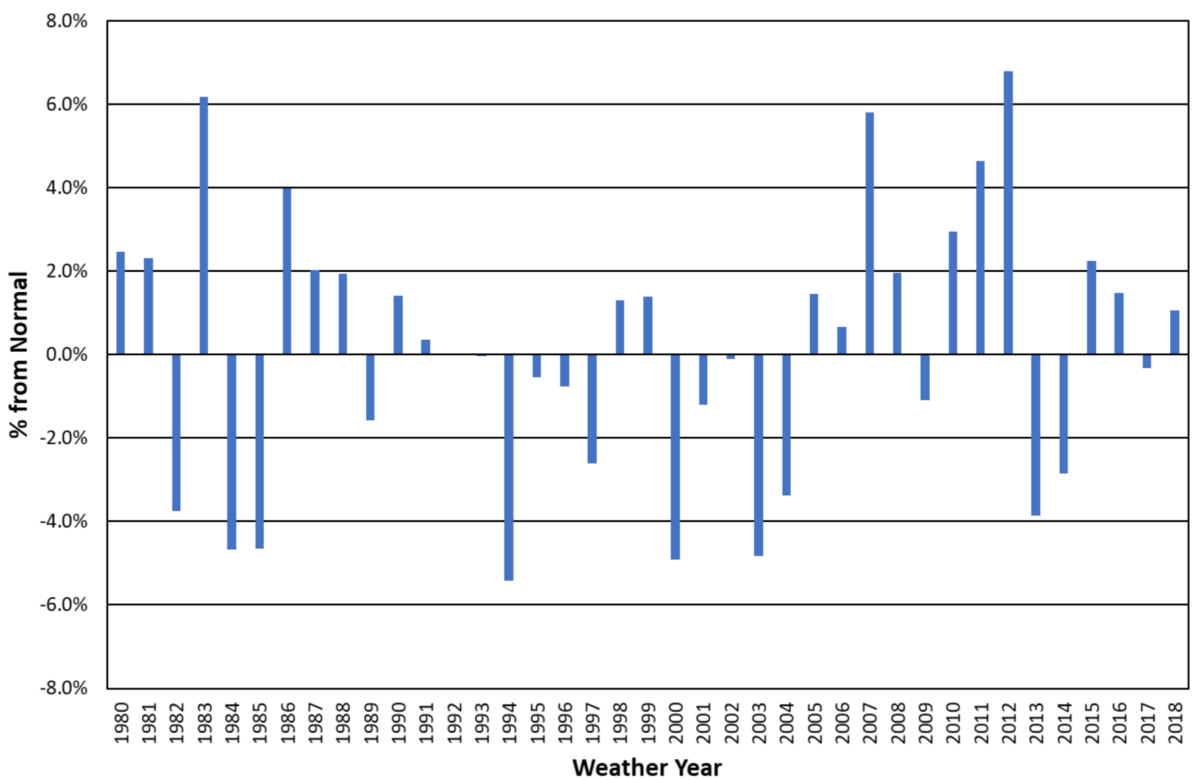


Figure 3. DEP Winter Peak Weather Variability

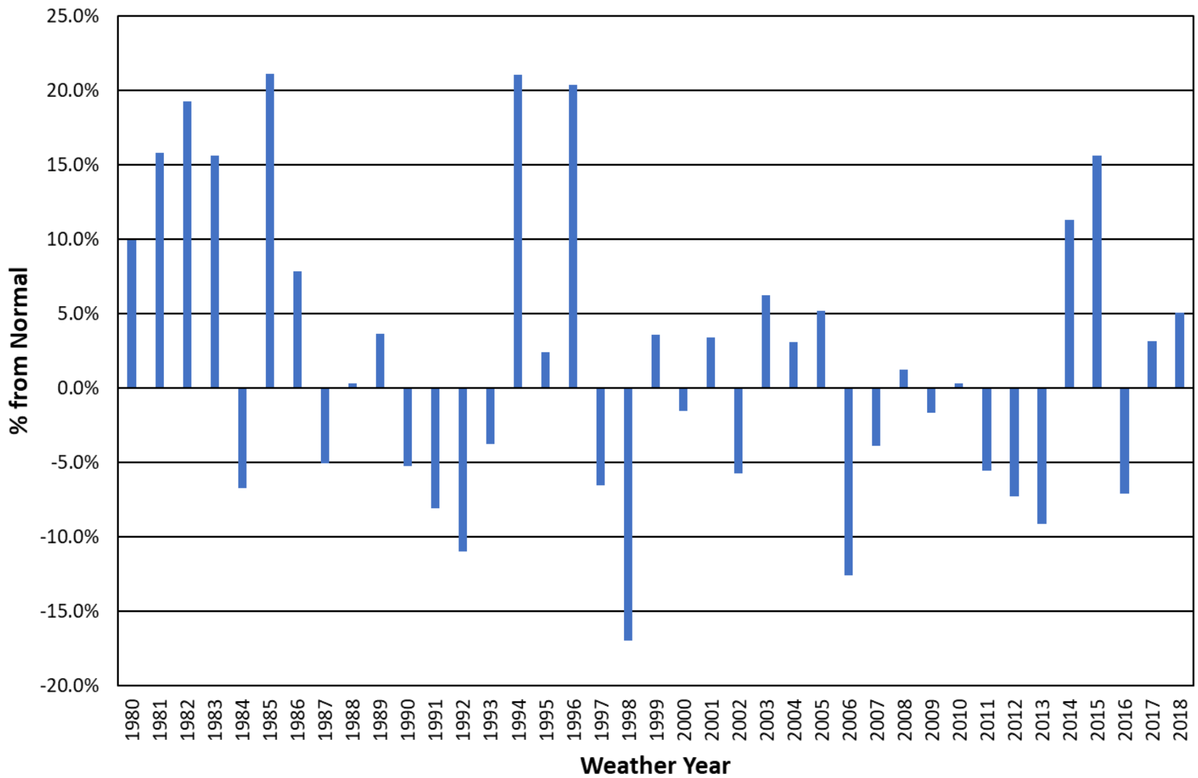
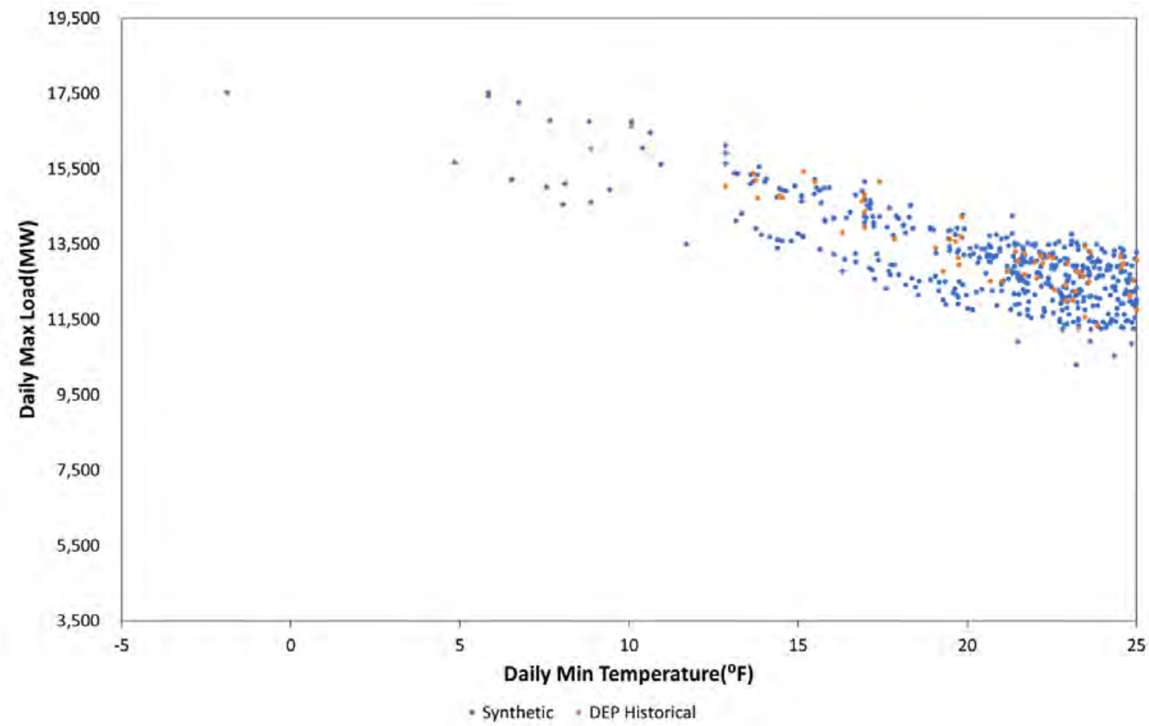


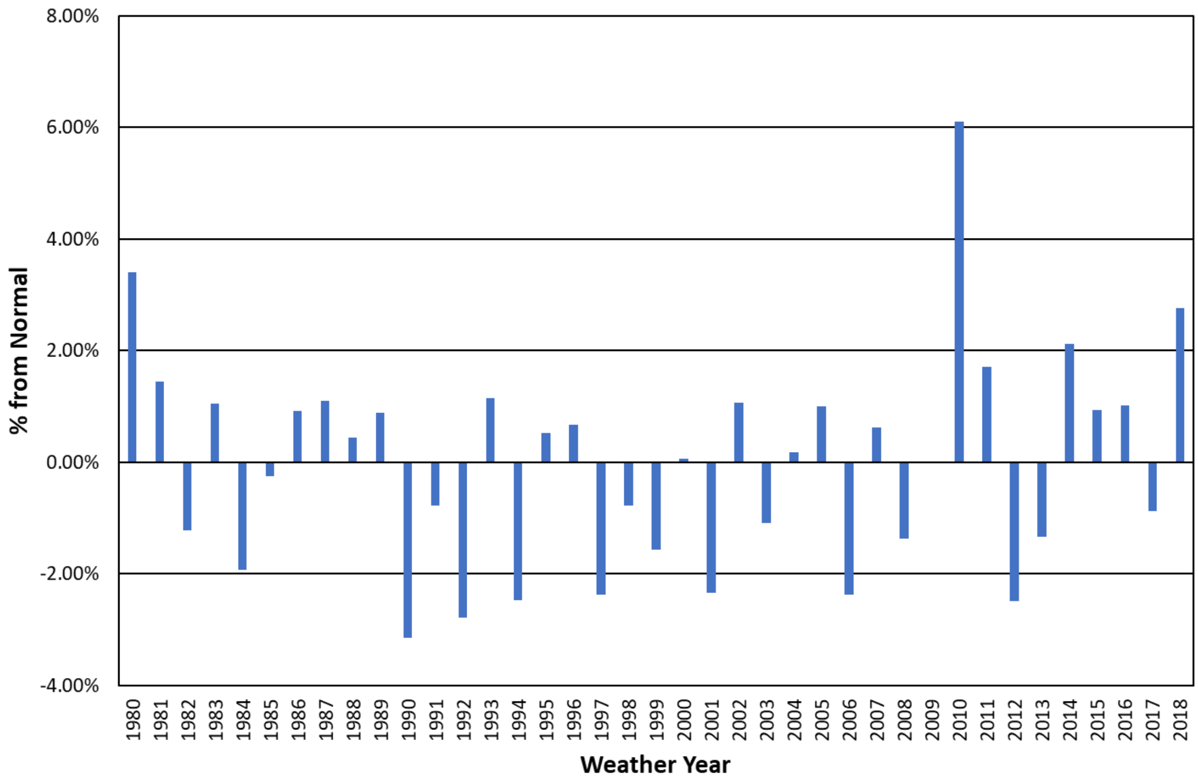
Figure 4 shows a daily peak load comparison of the synthetic load shapes and DEP history as a function of temperature. The predicted values align well with the history. Because recent historical observations only recorded a single minimum temperature of seven degrees Fahrenheit, Astrapé estimated the extrapolation for extreme cold weather days using regression analysis on the historical data. This figure highlights that the frequency of cold weather events is captured as it has been seen in history. The worst day seen in the thirty-nine year history was negative three degrees Fahrenheit. As shown in the following figure, the load associated with this day was capped very close to the six degree Fahrenheit day to assume saturation, however, the Company is skeptical that there would be much saturation on cold winter days because customers have continued to turn on additional heating options such as space heaters, ovens, etc.

Figure 4. DEP Winter Calibration



The energy variation is lower than peak variation across the weather years as expected. As shown in Figure 5, 2010 was an extreme year in total energy due to persistent severe temperatures across the summer and yet the deviation from average was only 6%.

Figure 5. DEP Annual Energy Variability



The synthetic shapes described above were then scaled to the forecasted seasonal energy and peaks within SERVM. Because DEP's load forecast is based on thirty years of weather, the shapes were scaled so that the average of the last thirty years equaled the forecast.

Synthetic loads for each external region were developed in a similar manner as the DEP loads. A relationship between hourly weather and publicly available hourly load[19] was developed based on recent history, and then this relationship was applied to thirty-nine years of weather data to develop thirty-nine synthetic load shapes. Tables 2 and 3 show the resulting weather diversity between DEP and external regions for both summer and winter loads. When the system, which includes all

[19] Federal Energy Regulatory Commission (FERC) 714 Forms were accessed during January of 2020 to pull hourly historical load for all neighboring regions.

regions in the study, is at its winter peak, the individual regions are approximately 2% - 9% below their non-coincidental peak load on average over the thirty-nine year period, resulting in an average system diversity of 4.7%. When DEP is at its winter peak load, DEC is 2.7% below its peak load on average while other regions are approximately 3 - 9% below their winter peak loads on average. Similar values are seen during the summer.

Table 2. External Region Summer Load Diversity

Load Diversity (% below non coincident average peak)	DEC	DEP	SOCO	TVA	SC	SCEG	PJM S	PJM W	System
At System Coincident Peak	3.4%	3.8%	5.2%	4.2%	6.8%	7.0%	3.7%	1.4%	N/A
At DEP Peak	2.0%	N/A	8.0%	6.8%	7.3%	7.1%	5.7%	9.6%	3.6%

Table 3. External Region Winter Load Diversity

Load Diversity (% below non coincident average peak)	DEC	DEP	SOCO	TVA	SC	SCEG	PJM S	PJM W	System
At System Coincident Peak	2.5%	2.8%	2.8%	5.8%	8.9%	4.8%	6.9%	3.2%	N/A
At DEP Peak	2.7%	N/A	4.7%	8.4%	6.7%	3.0%	5.2%	8.9%	2.4%

D. Economic Load Forecast Error

Economic load forecast error multipliers were developed to isolate the economic uncertainty that Duke has in its four year ahead load forecasts. Four years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans. To estimate the economic load forecast error, the difference between Congressional Budget Office (CBO) Gross Domestic Product (GDP) forecasts four years ahead and actual data was fit to a distribution which weighted over-forecasting more heavily than under-forecasting load[20]. This was a direct

[20] CBO's Economic Forecasting Record: 2017 Update. www.cbo.gov/publication/53090
www.cbo.gov/publication/53090

change accepted as part of the feedback in stakeholder meetings.[21] Because electric load grows at a slower rate than GDP, a 40% multiplier was applied to the raw CBO forecast error distribution. Table 4 shows the economic load forecast multipliers and associated probabilities. As an illustration, 25% of the time, it is expected that load will be over-forecasted by 2.7% four years out. Within the simulations, when DEP over-forecasts load, the external regions also over-forecast load. The SERVM model utilized each of the thirty-nine weather years and applied each of these five load forecast error points to create 195 different load scenarios. Each weather year was given an equal probability of occurrence.

Table 4. Load Forecast Error

Load Forecast Error Multipliers	Probability %
0.958	10.0%
0.973	25.0%
1.00	40.0%
1.02	15.0%
1.031	10.0%

E. Conventional Thermal Resources

DEP resources are outlined in Tables 5 and 6 and represent summer ratings and winter ratings. All thermal resources are committed and dispatched to load economically. The capacities of the units are defined as a function of temperature in the simulations. Full winter rating is achieved at 35°F and below and summer rating is assumed for 95° and above. For temperatures in between 35°F and 95°F, a simple linear regression between the summer and winter rating was utilized for each unit.

[21] Including the economic load forecast uncertainty actually results in a lower reserve margin compared to a scenario that excludes the load forecast uncertainty since over-forecasting load is weighted more heavily than under-forecasting load.

Table 5. DEP Baseload and Intermediate Resources

Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)	Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)
Mayo 1	Coal	727	746	Smith CC 4	NG - Combined Cycle	476	570
Roxboro 1	Coal	379	380	Smith CC 5	NG - Combined Cycle	489	589
Roxboro 2	Coal	671	673	Smith CC 5_DF/PAG	NG – Duct Firing/Power Aug	65/43	61/30
Roxboro 3	Coal	694	698	Lee/Wayne CC 1	NG - Combined Cycle	794	990
Roxboro 4	Coal	698	711	Lee/Wayne CC 1_DF	NG – Duct Firing	94	69
Brunswick 1	Nuclear	938	975	Sutton CC 1	NG - Combined Cycle	536	658
Brunswick 2	Nuclear	932	953	Sutton CC 1_DF	NG - Duct Firing	71	61
Harris 1	Nuclear	964	1009	Asheville CC	NG - Combined Cycle	496	560
Robinson 2	Nuclear	741	797				

Table 6. DEP Peaking Resources

Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)	Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)
Blewett CT 1	Oil Peaker	13	17	Smith CT 3	NG Peaker	155	185
Blewett CT 2	Oil Peaker	13	17	Smith CT 4	NG Peaker	159	186
Blewett CT 3	Oil Peaker	13	17	Smith CT 6	NG Peaker	155	187
Blewett CT 4	Oil Peaker	13	17	Wayne CT 1	Oil Peaker	177	192
Asheville CT 3	NG Peaker	160	185	Wayne CT 2	Oil Peaker	174	192
Asheville CT 4	Natural Gas Peaker	160	185	Wayne CT 3	Oil/NG Peaker	173	193
Darl CT 12	NG Peaker	118	133	Wayne CT 4	Oil/NG Peaker	170	191
Darl CT 13	NG Peaker	116	133	Wayne CT 5	Oil/NG Peaker	163	195
LM6000 (Sutton)	NG Peaker	39	49	Weatherspoon CT 1	Oil Peaker	31	41
LM6000 (Sutton)	NG Peaker	39	49	Weatherspoon CT 2	Oil Peaker	31	41
Smith CT 1	NG Peaker	157	189	Weatherspoon CT 3	Oil Peaker	32	41
Smith CT 2	NG Peaker	156	187	Weatherspoon CT 4	Oil Peaker	30	41

DEP purchase contracts were modeled as shown in Confidential Appendix Table CA2. These resources were treated as traditional thermal resources and counted towards reserve margin. Confidential Appendix Table CA3 shows the fuel prices used in the study for DEP and its neighboring power systems.

F. Unit Outage Data

Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical Generating Availability Data System (GADS) data events for the period 2014-2019 are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. Units without historical data use history from similar technologies. The events are entered using the following variables:

Full Outage Modeling
Time-to-Repair Hours
Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

Maintenance Outages
Maintenance Outage Rate - % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods.

Planned Outages
The actual schedule for 2024 was used.

To illustrate the outage logic, assume that from 2014 – 2019, a generator had 15 full outage events and 30 partial outage events reported in the GADS data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data. These multiple Time-to-Repair and Time-to-Fail inputs are the distributions used by SERVM. Because there may be seasonal variances in EFOR, the data is broken up into seasons such that there is a set of Time-to-Repair and Time-to-Fail inputs for summer, shoulder, and winter, based on history. Further, assume the generator is online in hour 1 of the simulation. SERVM will randomly draw both a full outage and partial outage Time-to-Fail value from the distributions provided. Once the unit has been economically dispatched for that amount of time, it will fail. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. The full outage counters and partial outage counters run in parallel. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture. Confidential Appendix Table CA4 shows system peak season Equivalent Forced Outage Rate (EFOR) for the system and by unit.

The most important aspect of unit performance modeling in resource adequacy studies is the cumulative MW offline distribution. Most service reliability problems are due to significant coincident outages. Confidential Appendix Figure CA1 shows the distribution of modeled system outages as a percentage of time modeled and compared well with actual historical data.

Additional analysis was performed to understand the impact cold temperatures have on system outages. Confidential Appendix Figures CA2 and CA3 show the difference in cold weather outages during the 2014-2019 period and the 2016-2019 period. The 2014-2019 period showed more events than the 2016-2019 period which is logical because Duke Energy has put practices in place to enhance reliability during these periods, however the 2016 – 2019 data shows some events still occur. The average capacity offline below 10 degrees for DEC and DEP combined was 400 MW. Astrapé split this value by peak load ratio and included 140 MW in the DEP Study and 260 MW in the DEC Study at temperatures below 10 degrees. Sensitivities were performed with the cold weather outages removed and increased to match the 2014 – 2019 dataset which showed an average of 800 MW offline on days below 10 degrees. The MWs offline during the 10 coldest days can be seen in Confidential Appendix Table CA5. The outages shown are only events that included some type of freezing or cold weather problem as part of the description in the outage event.

G. Solar and Battery Modeling

Table 7 shows the solar and battery resources captured in the study.

Table 7. DEP Renewable Resources Excluding Existing Hydro

Unit Type	Summer Capacity (MW)	Winter Capacity (MW)	Modeling
Utility Owned-Fixed	141	141	Hourly Profiles
Transition-Fixed	2,432	2,432	Hourly Profiles
Competitive Procurement of Renewable Energy (CPRE) Tranche 1 Fixed 40%/Tracking 60%	86	86	Hourly Profiles
Future Solar Fixed 40%/Tracking 60%	1,448	1,448	Hourly Profiles
Total Solar	4,107	4,107	
Total Battery	83	83	Modeled as energy arbitrage

The solar units were simulated with thirty-nine solar shapes representing thirty-nine years of weather. The solar shapes were developed by Astrapé from data downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) Data Viewer. The data was then input into NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles for both fixed and tracking solar profiles. The solar capacity was given 20% credit in the summer and 1% in the winter for reserve margin calculations based on the 2018 Solar Capacity Value Study. Figure 6 shows the county locations that were used and Figure 7 shows the average August output for different fixed-tilt and single-axis-tracking inverter loading ratios.

Figure 6. Solar Map

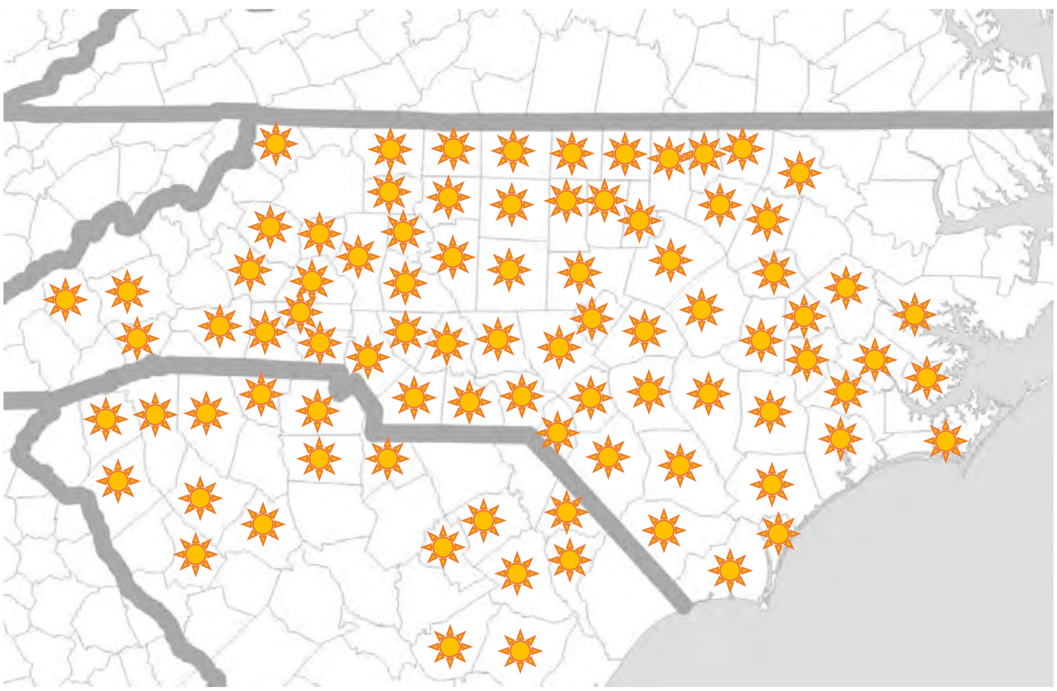
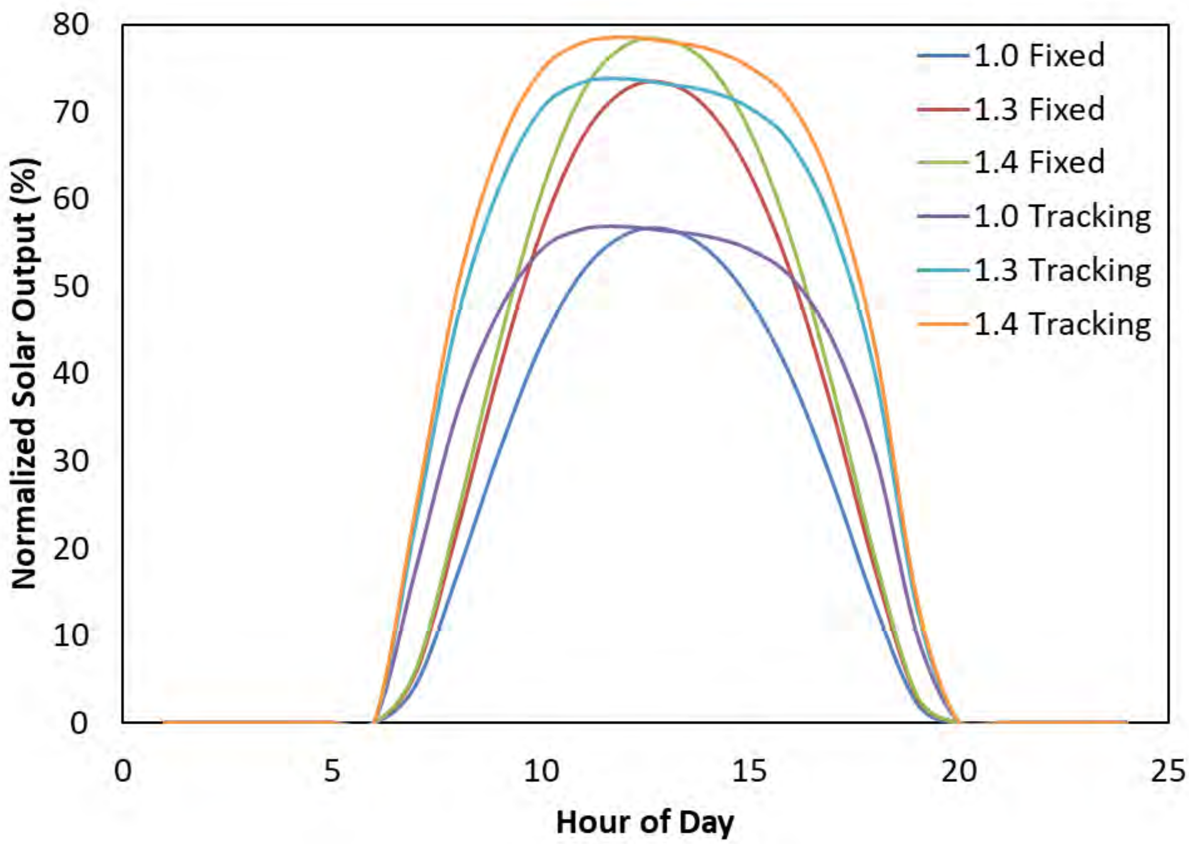


Figure 7. Average August Output for Different Inverter Loading Ratios



H. Hydro Modeling

The scheduled hydro is used for shaving the daily peak load but also includes minimum flow requirements. Figure 8 shows the total breakdown of scheduled hydro based on the last thirty-nine years of weather.

Figure 8. Scheduled Capacity

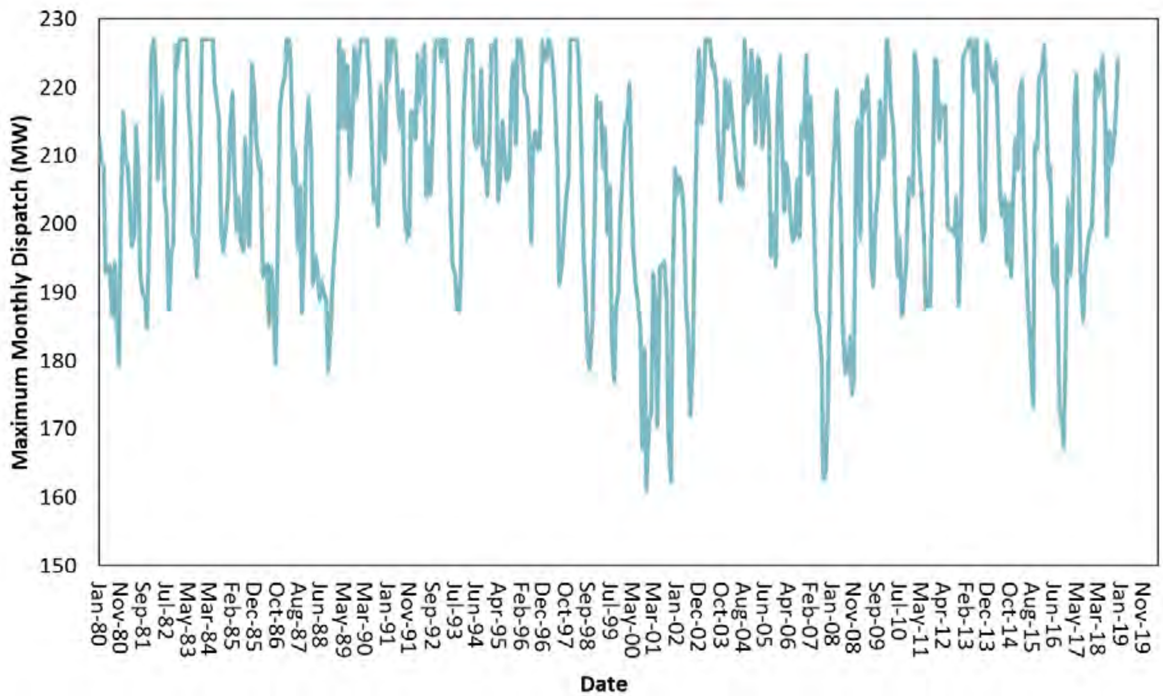
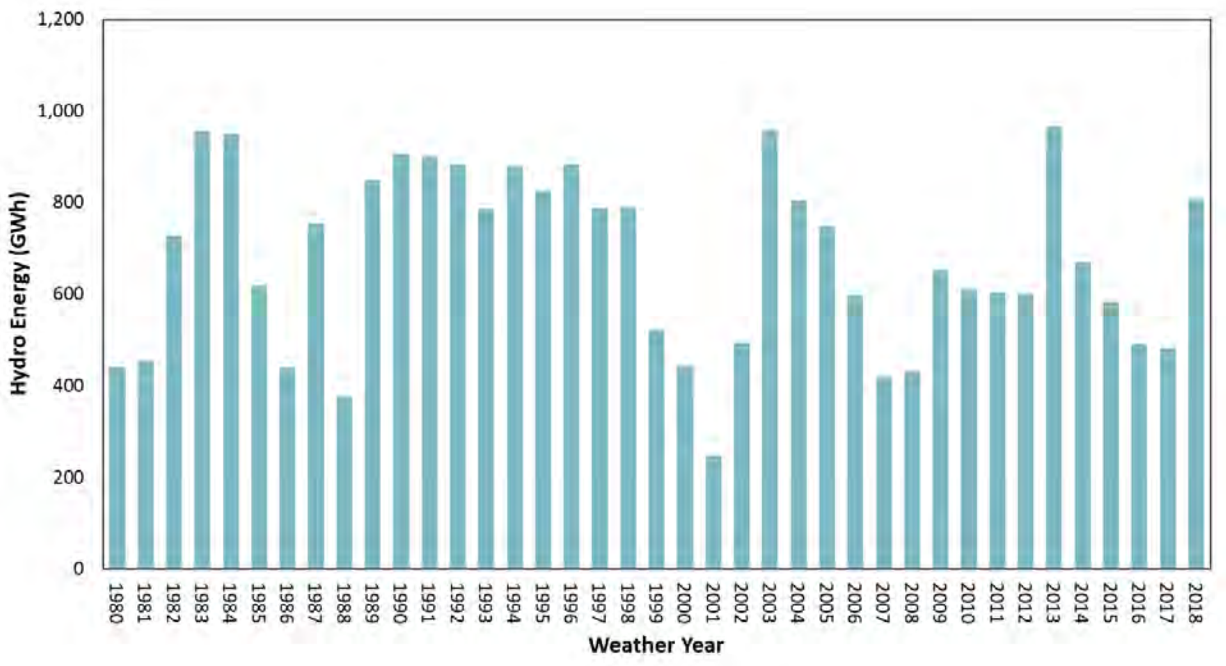


Figure 9 demonstrates the variation of hydro energy by weather year which is input into the model. The lower rainfall years such as 2001, 2007, and 2008 are captured in the reliability model with lower peak shaving as shown in Figure 9.

Figure 9. Hydro Energy by Weather Year



I. Demand Response Modeling

Demand response programs are modeled as resources in the simulations. They are modeled with specific contract limits including hours per year, days per week, and hours per day constraints. For this study, 1,001 MW of summer capacity and 461 MW of winter capacity were included as shown in Table 8. To ensure these resources were called after conventional generation, a $2,000/MWh strike price was included.

Table 8. DEP Demand Response Modeling

Region	Program	Summer Capacity (MW)	Winter Capacity (MW)	Hours Per Year	Days Per Week	Hours Per Day
DEP	EnergyWise Home	430	22	60	7	4
DEP	EnergyWise Business	22	2	60	7	4
DEP	Demand Response Automation	44	24	80	7	8
DEP	Large Load Curtailable	265	245	100	7	8
DEP	Distribution System Demand Response	240	168	100	7	8
	Total DEP	1,001	461			

J. Operating Reserve Requirements

The operating reserves assumed for DEP are shown below. SERVM commits to this level of operating reserves in all hours. However, all operating reserves except for the 150 MW of regulation are allowed to be depleted during a firm load shed event.

- Regulation Up/Down: 150 MW
- Spinning Requirement: 200 MW
- Non-Spin Requirement: 200 MW
- Additional Load Following Due to Intermittent Resources in 2024: Hourly values were used based on a 12x24 profile provided by Duke Energy from its internal modeling.

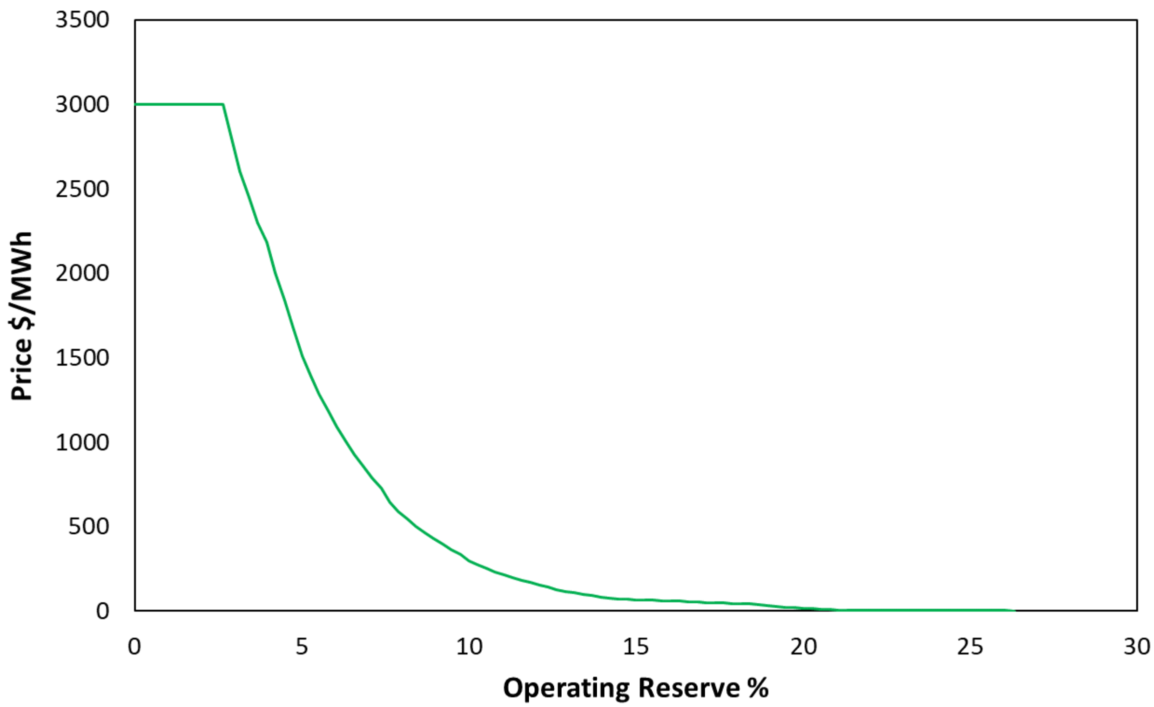
K. External Assistance Modeling

The external market plays a significant role in planning for resource adequacy. If several of the DEP resources were experiencing an outage at the same time, and DEP did not have access to surrounding markets, there is a high likelihood of unserved load. To capture a reasonable amount of assistance from surrounding neighbors, each neighbor was modeled at the one day in 10-year standard (LOLE of 0.1) level representing the target for many entities. By modeling in this manner, only weather diversity and generator outage diversity benefits are captured. The market representation used in SERVM is based on Astrapé's proprietary dataset which is developed based on FERC Forms, Energy Information Administration (EIA) Forms, and reviews of IRP information from neighboring regions. To ensure purchases in the model compared well in magnitude to historical data, the years 2015 and 2018 were simulated since they reflected cold weather years with high winter peaks. Figure CA4 in the confidential appendix shows that calibration with purchases on the y-axis and load on the x-axis for the 2015 and 2018 weather years. The actual purchases and modeled results show DEP purchases significant capacity during high load hours during these years.

The cost of transfers between regions is based on marginal costs. In cases where a region is short of resources, scarcity pricing is added to the marginal costs. As a region's hourly reserves approach zero, the scarcity pricing for that region increases. Figure 10 shows the scarcity pricing curve that was used in the simulations. It should be noted that the frequency of these scarcity prices is very low because in the majority of hours, there is plenty of capacity to meet load after the market has cleared[22].

[22]The market clearing algorithm within SERVM attempts to get all regions to the same price subject to transmission constraints. So, if a region's original price is $3,000/MWh based on the conditions and scarcity pricing in that region alone, it is highly probable that a surrounding region will provide enough capacity to that region to bring prices down to reasonable levels.

Figure 10. Operating Reserve Demand Curve (ORDC)



L. Cost of Unserved Energy

Unserved energy costs were derived from national studies completed for the Department of Energy (DOE) in 2003[23] and 2009[24], along with three other studies performed[25] previously by other consultants. The DOE studies were compilations of other surveys performed by utilities over the last two decades. All studies split the customer class categories into residential, commercial, and industrial. The values were then applied to the actual DEP customer class mix to develop a wide

[23] https://eta-publications.lbl.gov/sites/default/files/lbnl-54365.pdf https://eta-publications.lbl.gov/sites/default/files/lbnl-54365.pdf
[24] https://eta-publications.lbl.gov/sites/default/files/lbnl-2132e.pdf https://eta-publications.lbl.gov/sites/default/files/lbnl-2132e.pdf
[25] https://pdfs.semanticscholar.org/544b/d740304b64752b451d749221a00eede4c700.pdf
Peter Cramton, Jeffrey Lien. Value of Lost Load. February 14, 2000.

range of costs for unserved energy. Table 9 shows those results. Because expected unserved energy costs are so low near the economic optimum reserve margin, this value, while high in magnitude, is not a significant driver in the economic analysis. Since the public estimates ranged significantly, DEP used $16,450/MWh for the Base Case in 2024, and sensitivities were performed around this value from $5,000 MWh to $25,000 MWh to understand the impact.

Table 9. Unserved Energy Costs / Value of Lost Load

	Weightings	2003 DOE Study 2024 $/kWh	2009 DOE Study 2024 $/kWh	Christiansen Associates 2024 $/kWh	Billinton and Wacker 2024 $/kWh	Karuiki and Allan 2024 $/kWh
Residential	43%	1.57	1.50	3.12	2.73	1.26
Commercial	33%	35.54	109.23	22.37	23.24	24.74
Industrial	24%	20.51	32.53	11.59	23.24	58.65
	Weighted Average $/kWh	17.31	44.55	11.50	14.38	22.60
	Average $/kWh	22.07				
	Average $/kWh excluding the 2009 DOE Study	16.45				

M. System Capacity Carrying Costs

The study assumes that the cheapest marginal resource is utilized to calculate the carrying cost of additional capacity. The cost of carrying incremental reserves was based on the capital and FOM of a new simple cycle natural gas Combustion Turbine (CT) consistent with the Company's IRP assumptions. For the study, the cost of each additional kW of reserves can be found in Confidential Appendix Table CA6. The additional CT units were forced to have a 5% EFOR in the simulations and used to vary reserve margin in the study.

IV. Simulation Methodology

Since most reliability events are high impact, low probability events, a large number of scenarios must be considered. For DEP, SERVM utilized thirty-nine years of historical weather and load shapes, five points of economic load growth forecast error, and fifteen iterations of unit outage draws for each scenario to represent a distribution of realistic scenarios. The number of yearly simulation cases equals 39 weather years * 5 load forecast errors * 15 unit outage iterations = 2,925 total iterations for the Base Case. This Base Case, comprised of 2,925 total iterations, was re-run at different reserve margin levels by varying the amount of CT capacity.

A. Case Probabilities

An example of probabilities given for each case is shown in Table 10. Each weather year is given equal probability and each weather year is multiplied by the probability of each load forecast error point to calculate the case probability.

Table 10. Case Probability Example

Weather Year	Weather Year Probability (%)	Load multipliers Due to Load Economic Forecast Error (%)	Load Economic Forecast Error Probability (%)	Case Probability (%)
1980	2.56	95.8	10	0.256
1980	2.56	97.3	25	0.64
1980	2.56	100	40	1.024
1980	2.56	102	15	0.384
1980	2.56	103.1	10	0.256
1981	2.56	95.8	10	0.256
1981	2.56	97.3	25	0.64
1981	2.56	100	40	1.024
1981	2.56	102	15	0.384
1981	2.56	103.1	10	0.256
1982	2.56	95.8	10	0.256
1982	2.56	97.3	25	0.64
1982	2.56	100	40	1.024
1982	2.56	102	15	0.384

1982	2.56	103.1	10	0.256
...	...	...	...	...
...	...	...	...	...
2018	2.56	103.1	10	0.256
			Total	100

For this study, LOLE is defined in number of days per year and is calculated for each of the 195 load cases and weighted based on probability. When counting LOLE events, only one event is counted per day even if an event occurs early in the day and then again later in the day. Across the industry, the traditional 1 day in 10 year LOLE standard is defined as 0.1 LOLE. Additional reliability metrics calculated are Loss of Load Hours (LOLH) in hours per year and Expected Unserved Energy (EUE) in MWh.

Total system energy costs are defined as the following for each region:

$$Production\ Costs\ (Fuel\ Burn + Variable\ O\&M) +\ Purchase\ Costs - Sales\ Revenue \\ + Loss\ of\ Reserves +\ Cost\ of\ Unserved\ Energy$$

These components are calculated for each case and weighted based on probability to calculate total system energy costs for each scenario simulated. Loss of Reserves costs recognize the additional risk of depleting operating reserves and are costed out at the ORDC curve when they occur. As shown in the results these costs are almost negligible. The cost of unserved energy is simply the MWh of load shed multiplied by the value of lost load. System capacity costs are calculated separately outside of the SERVM model using the economic carrying cost of a new CT.

B. Reserve Margin Definition

For this study, winter and summer reserve margins are defined as the following:

- (Resources – Demand) / Demand
  - Demand is 50/50 peak forecast
  - Demand response programs are included as resources and not subtracted from demand
  - Solar capacity is counted at 1% capacity credit for winter reserve margin calculations, 20% for summer reserve margin calculations, and the small amount of battery capacity was counted at 80%.

As previously noted, the Base Case was simulated at different reserve margin levels by varying the amount of CT capacity in order to evaluate the impact of reserves on LOLE. In order to achieve lower reserve margin levels, capacity needed to be removed. For DEP, purchase capacity was removed to achieve lower reserve margin levels. Table 11 shows a comparison of winter and summer reserve margin levels for the Base Case. As an example, when the winter reserve margin is 16%, the resulting summer reserve margin is 28.2% due to the lower summer peak demand and 4,107 MW of solar on the system which provides greater summer capacity contribution.

Table 11. Relationship Between Winter and Summer Reserve Margin Levels

Winter	10.0%	12.0%	14.0%	16.0%	18.0%	20.0%
Corresponding Summer	22.3%	24.2%	26.2%	28.2%	30.2%	32.1%

V. Physical Reliability Results

Table 12 shows LOLE by month across a range of reserve margin levels for the Island Case. The analysis shows all of the LOLE falls in the winter. To achieve reliability equivalent to the 1 day in 10 year standard (0.1 LOLE) in the Island scenario, a 25.5% winter reserve margin is required. Given the significant solar on the system, the summer reserves are approximately 12% greater than winter reserves which results in no reliability risk in the summer months. This 25.5% reserve margin is required to cover the combined risks seen in load uncertainty, weather uncertainty, and generator performance for the DEP system.

Table 12. Island Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
10.0%	22.3%	0.43	0.09	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.70	0.71
11.0%	23.2%	0.37	0.08	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.61	0.62
12.0%	24.2%	0.32	0.07	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.53	0.54
13.0%	25.2%	0.28	0.06	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.47	0.47
14.0%	26.2%	0.25	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.41	0.41
15.0%	27.2%	0.21	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.35	0.36
16.0%	28.2%	0.19	0.05	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.31	0.31
17.0%	29.1%	0.17	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.28	0.28
18.0%	30.1%	0.15	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.25	0.25
19.0%	31.1%	0.13	0.04	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.22	0.22
20.0%	32.1%	0.12	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.20	0.20
21.0%	33.1%	0.11	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.18	0.18
22.0%	34.1%	0.10	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.16	0.16
23.0%	35.1%	0.09	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.14	0.14
24.0%	36.0%	0.08	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.12	0.12
25.0%	37.0%	0.07	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.11	0.11
26.0%	38.0%	0.06	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.10	0.10

Table 13 shows LOLE by month across a range of reserve margin levels for the Base Case which assumes neighbor assistance. As in the Island scenario, all of the LOLE occurs in the winter showing the same increased risk in the winter. To achieve reliability equivalent to the 1 day in 10 year standard (0.1 LOLE) in this scenario that includes market assistance, a 19.25% winter reserve margin is required.

Table 13. Base Case Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
10.0%	22.3%	0.14	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.23	0.23
11.0%	23.2%	0.13	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.21	0.21
12.0%	24.2%	0.12	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.19	0.19
13.0%	25.2%	0.11	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.18	0.18
14.0%	26.2%	0.10	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.16	0.16
15.0%	27.2%	0.09	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.15	0.15
16.0%	28.2%	0.08	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.13	0.13
17.0%	29.1%	0.07	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.12	0.12
18.0%	30.1%	0.07	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.11	0.11
19.0%	31.1%	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.10	0.10
20.0%	32.1%	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
21.0%	33.1%	0.05	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
22.0%	34.1%	0.05	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08

Table 14 shows LOLE and other physical reliability metrics by reserve margin for the Base Case simulations. Loss of Load Hours (LOLH) is expressed in hours per year and Expected Unserved Energy (EUE) is expressed in MWh. The table shows that an 8% reserve margin results in an LOLH of 0.92 hours per year. Thus, to achieve 2.4 hours per year, which is far less stringent than the 1 day in 10 year standard (1 event in 10 years), DEP would require a reserve margin less than 8%. Astrapé does not recommend targeting a standard that allows for 2.4 hours of firm load shed every year as essentially would expect a firm load shed during peak periods ever year. The hours per event can be calculated by dividing LOLH by LOLE. The firm load shed events last approximately 2-3 hours on average. As these reserve margins decrease and firm load shed events increase, it is expected that reliance on external assistance, depletion of contingency reserves, and more demand response calls will occur and increase the overall reliability risk on the system.

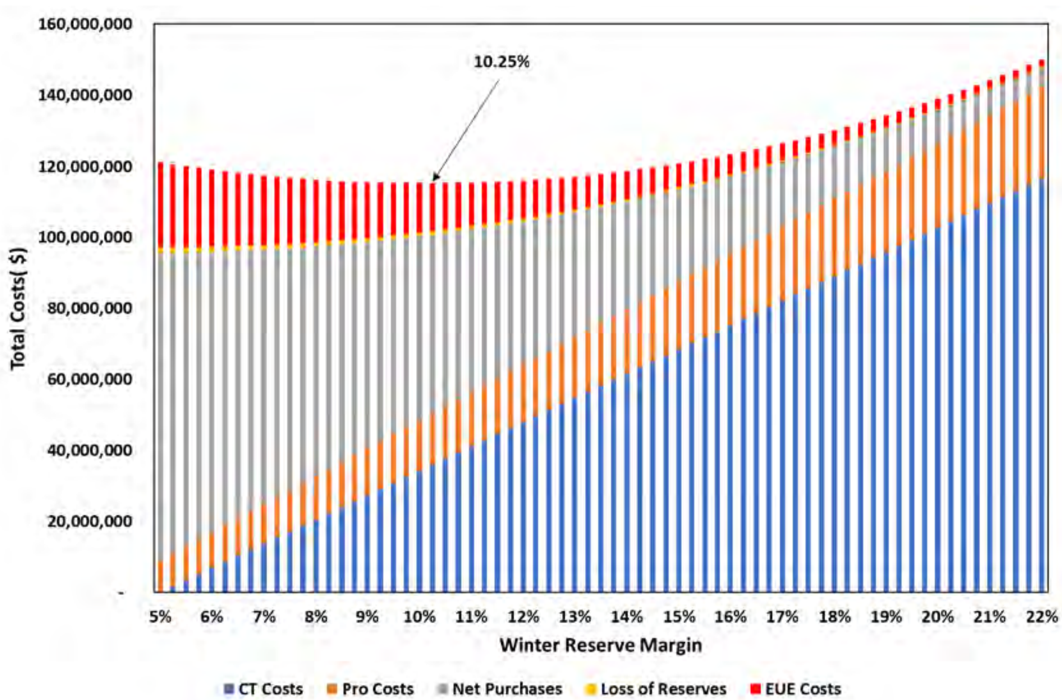
Table 14. Reliability Metrics: Base Case

Reserve Margin	LOLE	LOLH	EUE
%	**Days Per Year**	**Hours Per Year**	**MWh**
8.0%	0.272	0.92	1,075
8.5%	0.261	0.88	1,016
9.0%	0.251	0.84	959
9.5%	0.241	0.80	904
10.0%	0.231	0.77	850
10.5%	0.222	0.73	799
11.0%	0.212	0.70	749
11.5%	0.203	0.66	701
12.0%	0.195	0.63	655
12.5%	0.186	0.60	611
13.0%	0.178	0.56	568
13.5%	0.170	0.53	528
14.0%	0.163	0.51	489
14.5%	0.155	0.48	452
15.0%	0.148	0.45	417
15.5%	0.141	0.42	384
16.0%	0.135	0.40	352
16.5%	0.129	0.38	322
17.0%	0.123	0.35	294
17.5%	0.117	0.33	268
18.0%	0.112	0.31	244
18.5%	0.106	0.29	222
19.0%	0.102	0.27	201
19.5%	0.097	0.26	182
20.0%	0.093	0.24	165
20.5%	0.089	0.22	150
21.0%	0.085	0.21	137
21.5%	0.082	0.20	125
22.0%	0.078	0.18	115
22.5%	0.076	0.17	107
23.0%	0.073	0.16	101
23.5%	0.071	0.15	97
24.0%	0.068	0.15	95
24.5%	0.067	0.14	94
25.0%	0.065	0.13	95

VI. Base Case Economic Results

While Astrapé believes physical reliability metrics should be used for determining planning reserve margin because customers expect to have power during extreme weather conditions, customer costs provide additional information in resource adequacy studies. From a customer cost perspective, total system costs were analyzed across reserve margin levels for the Base Case. Figure 11 shows the risk neutral costs at the various winter reserve margin levels. This risk neutral represents the weighted average results of all weather years, load forecast uncertainty, and unit performance iterations at each reserve margin level and represents the expected value on a year in and year out basis.

Figure 11. Base Case Risk Neutral Economic Results[26]

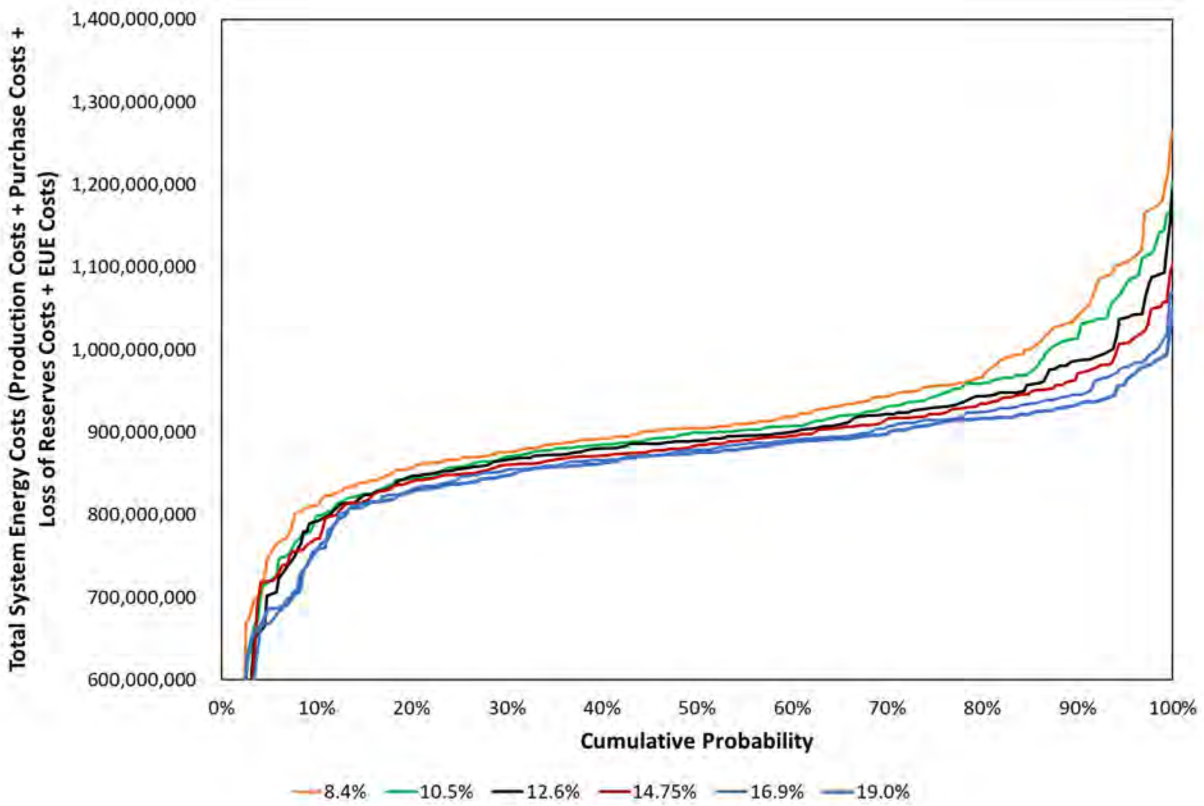


[26] Costs that are included in every reserve margin level have been removed so the reader can see the incremental impact of each category of costs. DEP has approximately 1 billion dollars in total costs.

As Figure 11 shows, the lowest risk neutral cost falls at a 10.25% reserve margin. The reason this risk neutral reserve margin is significantly lower than 19.25% reserve margin required to meet the 0.1 LOLE is due to high reserve margins in the summer. The majority of the savings seen in adding additional capacity is recognized in the winter.[27] The cost curve is fairly flat for a large portion of the reserve margin curve because when CT capacity is added there is always system energy cost savings from either reduction in loss of load events, savings in purchases, or savings in production costs. This risk neutral scenario represents the weighted average of all scenarios but does not illustrate the impact of high-risk scenarios that could cause customer rates to be volatile from year to year. Figure 12, however, shows the distribution of system energy costs (production costs, purchase costs, loss of reserves costs, and the costs of EUE) at different reserve margin levels. This figure excludes fixed CT costs which increase with reserve margin level. As reserves are added, system energy costs decline. By moving from lower reserve margins to higher reserve margins, the volatile right side of the curve (greater than 85% Cumulative Probability) is dampened, shielding customers from extreme scenarios for relatively small increases in annual expected costs. By paying for additional CT capacity, extreme scenarios are mitigated.

[27] As the DEC study shows, the lower DEC summer reserve margins increase the risk neutral economic reserve margin level compared to the DEP Study.

Figure 12. Cumulative Probability Curves



The next table shows the same data laid out in tabular format. It includes the weighted average results as shown in Figure 11 as well as the energy savings at higher cumulative probability levels. As shown in the table, going from the risk neutral reserve margin of 10.25% to 17%, customer costs on average increase by 11 million dollars a year[28] and LOLE is reduced from 0.23 to 0.12 events per year. The LOLE for the island scenario decreases from 0.71 days per year to 0.28 days per year. However, 10% of the time energy savings are greater than or equal to $67 million if a 17% reserve margin is maintained versus the 10.25% reserve margin. And 5% of the time, $101 million or more is saved.

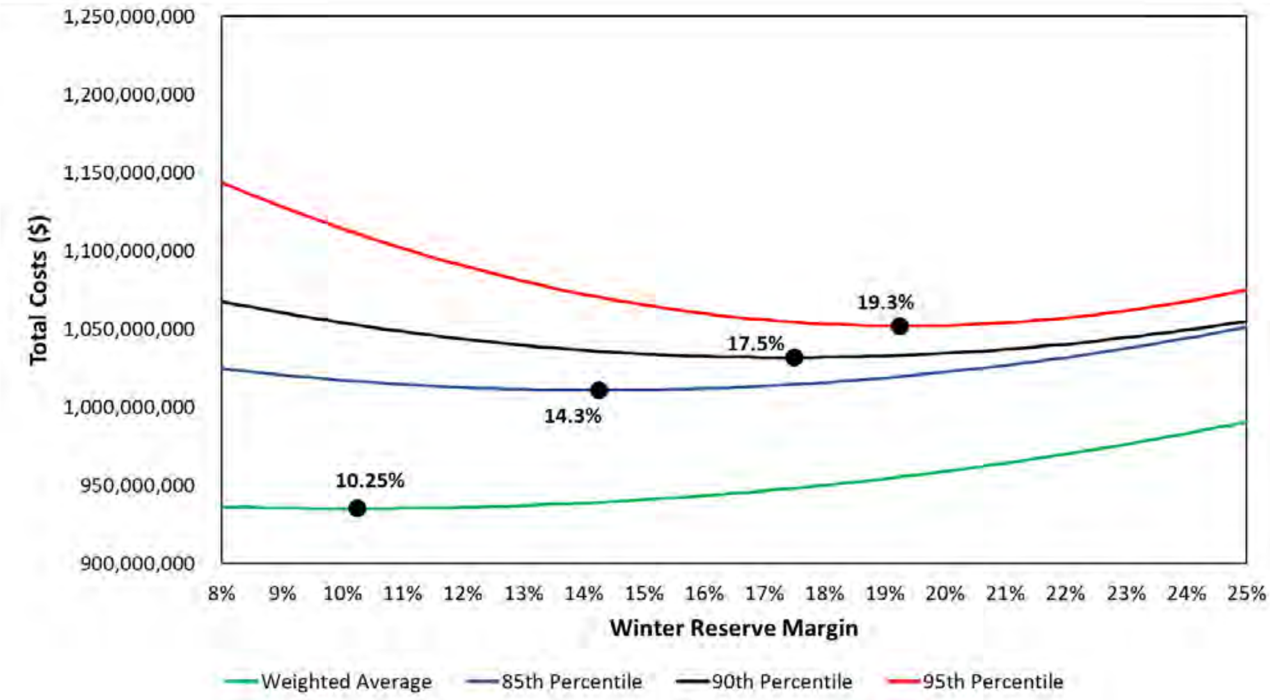
[28] This includes $46 million for CT costs and $35 million of system energy savings.

Table 15. Annual Customer Costs vs LOLE

Reserve Margin	Change in Capital Costs ($M)	Change in Energy Costs ($M)	Total Weighted Average Costs ($M)	85th Percentile Change in Energy Costs ($M)	90th Percentile Change in Energy Costs ($M)	95th Percentile Change in Energy Costs ($M)	LOLE (Days Per Year)	LOLE (Days Per Year) Island Sensitivity
10.25%	-	-	-	-	-	-	0.23	0.71
11.00%	5.1	-5.0	0.2	-7.1	-9.3	-14.5	0.21	0.62
12.00%	12.0	-11.2	0.8	-15.9	-20.9	-32.5	0.19	0.54
13.00%	18.8	-16.9	1.9	-24.0	-31.8	-49.1	0.18	0.47
14.00%	25.7	-22.2	3.5	-31.4	-41.8	-64.3	0.16	0.41
15.00%	32.5	-26.9	5.6	-38.0	-51.0	-78.0	0.15	0.36
16.00%	39.4	-31.2	8.2	-44.0	-59.4	-90.3	0.13	0.31
17.00%	46.2	-34.9	11.3	-49.3	-67.0	-101.2	0.12	0.28
18.00%	53.1	-38.1	14.9	-53.9	-73.7	-110.7	0.11	0.25
19.00%	59.9	-40.8	19.1	-57.8	-79.7	-118.7	0.1	0.22
20.00%	66.7	-43.0	23.8	-61.0	-84.8	-125.3	0.09	0.2

The next figure takes the 85th, 90th, and 95th percentile points of the total system energy costs in Figure 12 and adds them to the fixed CT costs at each reserve margin level. It is rational to view the data this way because CT costs are more known with a small band of uncertainty while the system energy costs are volatile as shown in the previous figure. In order to attempt to put the fixed costs and the system energy costs on a similar basis in regards to uncertainty, higher cumulative probability points using the 85th – 95th percentile range can be considered for the system energy costs. While the risk neutral lowest cost curve falls at 10.25% reserve margin, the 85th to 95th percentile cost curves point to a 14-19% reserve margin.

Figure 13. Total System Costs by Reserve Margin



Carrying additional capacity above the risk neutral reserve margin level to reduce the frequency of firm load shed events in DEP is similar to the way PJM incorporates its capacity market to maintain the one day in 10-year standard (LOLE of 0.1). In order to maintain reserve margins that meet the one day in 10-year standard (LOLE of 0.1), PJM supplies additional revenues to generators through its capacity market. These additional generator revenues are paid by customers who in turn see enhanced system reliability and lower energy costs. At much lower reserve margin levels, generators can recover fixed costs in the market due to capacity shortages and more frequent high prices seen during these periods, but the one day in 10-year standard (LOLE of 0.1) target is not satisfied.

VII. Sensitivities

Several sensitivities were simulated in order to understand the effects of different assumptions on the 0.1 LOLE minimum winter reserve margin and to address questions and requests from stakeholders.

Outage Sensitivities

As previously noted, the Base Case included a total of 400 MW of cold weather outages between DEC and DEP below ten degrees Fahrenheit based on outage data for the period 2016-2019. Sensitivities were run to see the effect of two cold weather outage assumptions. The first assumed that the 400 MW of total outages between DEC and DEP below ten degrees Fahrenheit were removed. As Table 16 indicates, the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) is lowered by 0.75% from the Base Case to 18.50%. This shows that if the Company was able to eliminate all cold weather outage risk, it could carry up to a 0.75% lower reserve margin. However, Astrapé recognizes based on North American Electric Reliability Corporation (NERC) documentation across the industry[29] that outages during cold temperatures could be substantially more than the 400 MW being applied at less than 10 degrees in this modeling.

29 https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20WRA%202019_2020.pdfvv (page 5)

https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf

(beginning page 43)

Table 16. No Cold Weather Outage Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
No Cold Weather Outages	18.50%	9.50%	16.25%

The second outage sensitivity showed what the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) would need to be if cold weather outages were based solely on 2014-2019 historical data which increased the total MW of outages from 400 MW to 800 MW. Table 17 shows that the minimum reserve margin for 0.1 LOLE is 20.50 %.

Table 17. Cold Weather Outages Based on 2014-2019 Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Cold Weather Outages Based on 2014 - 2019	20.50%	10.50%	17.75%

Load Forecast Error Sensitivities

These sensitivities were run to see the effects of the Load Forecast Error (LFE) assumptions. In response to stakeholder feedback, an asymmetric LFE distribution was adopted in the Base Case which reflected a higher probability weighting on over-forecasting scenarios. In the first sensitivity, the LFE uncertainty was completely removed. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) increased by 0.75% to 20.00%. This demonstrates that the load forecast error assumed in the Base Case was reducing the target reserve margin levels since over-forecasting was more heavily weighted in the LFE distribution. Because of this result, Astrapé did not simulate additional sensitivities such as 2-year, 3-year, or 5-year LFE distributions.

Table 18. Remove LFE Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Remove LFE	20.00%	10.50%	17.50%

The second sensitivity removed the asymmetric Base Case distribution and replaced it with the originally proposed normal distribution. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) increased by 1.0% to 20.25%.

Table 19. Originally Proposed LFE Distribution Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Originally Proposed Normal Distribution	20.25%	11.25%	17.50%

Solar Sensitivities

The Base Case for DEP assumed that there was 4,107 MW of solar on the system. The first solar sensitivity decreased this number to 3,404 MW. This change in solar had no impact on the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) as the results in Table 20 show because the capacity contribution of solar in the winter reserve margin calculation is 1%.

Table 20. Low Solar Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Low Solar	19.25%	11.75%	17.50%

The second solar sensitivity increased the amount of solar on the DEP system to 4,629 MW. This increase also had very little impact on the minimum reserve margins as Table 21 indicates. Both of these results are expected as solar provides almost no capacity value in the winter.

Table 21. High Solar Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
High Solar	19.00%	9.50%	16.75%

Demand Response (DR) Sensitivity

In this scenario, the winter demand response is increased to 1,001 MW to match the summer capacity. It is important to note that DR is counted as a resource in the reserve margin calculation similar to a conventional generator. Simply increasing DR to 1,001 MW results in a higher reserve margin and lower LOLE compared to the Base Case. Thus, CT capacity was adjusted (lowered) in the high DR sensitivity to maintain the same reserve margin level. Results showed that the 0.1 LOLE minimum reserve margin actually increased from 19.25% to 20.00% due to demand response's dispatch limits compared to a fully dispatchable traditional resource. DR may be an economic alternative to installing CT capacity, depending on market potential and cost. However, it should be noted that while Duke counts DR and conventional capacity as equivalent in load carrying capability in its IRP planning, the sensitivity results show that DR may have a slightly lower equivalent load carrying capability especially for programs with strict operational limits. The results are listed in Table 22 below.

Table 22. Demand Response Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Demand Response Winter as High as Summer	20.00%	12.50%	18.50%

No Coal Sensitivity

In this scenario, all coal units were replaced with CC/CT units. The CC units were modeled with a 4% EFOR and the CT units were modeled with a 5% EFOR. Due to the low EFOR's of the DEP coal units, the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) increased slightly as shown in Table 23 below. Essentially these thermal resources were interchangeable and had a minimal impact on the reserve margin.

Table 23. No Coal Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Retire all Coal	19.50%	11.25%	17.50%

Climate Change Sensitivity

In this scenario, the loads were adjusted to reflect the temperature increase outlined in the National Oceanic and Atmospheric Administration (NOAA) Climate Change Analysis[30]. Based on NOAA's research, temperatures since 1981 have increased at an average rate of 0.32 degrees Fahrenheit per decade. Each synthetic load shape was increased to reflect the increase in temperature it would see to meet the 2024 Study Year. For example, 1980 has a 1.4 degree increase ($0.32 \frac{°F}{Decade} * \frac{1\ Decade}{10\ Year} * 44\ Years$). After the loads were adjusted, the analysis was rerun. The summer peaks saw an increase and the winter peaks especially in earlier weather years saw a decrease. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) is reduced to 18.50% from 19.25% in the Base Case under these assumptions. The results are listed in the table below.

Table 24. Climate Change Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Climate Change	18.50%	9.75%	16.25%

[30] https://www.climate.gov/news-features/understanding-climate/climate-change-global-temperature

VIII. Economic Sensitivities

Table 25 shows the economic results if the cost of unserved energy is varied from \$5,000/MWh to \$25,000/MWh and the cost of incremental capacity is varied from \$40/kW-yr to \$60/kW-yr. As CT costs decrease, the economic reserve margin increases and as CT costs increase, the economic reserve margin decreases. The opposite occurs with the cost of EUE. The higher the cost of EUE, the higher the economic target.

Table 25. Economic Sensitivities

	Economics	
Sensitivity	**Weighted Average (risk neutral)**	**90th %**
Base Case	10.25%	17.50%
CT costs \$40kW-yr	12.50%	18.75%
CT costs \$60/kW-yr	6.00%	15.25%
EUE 5,000 \$/MWh	7.00%	13.75%
EUE 25,000 \$/MWh	11.75%	19.25%

IX. DEC/DEP Combined Sensitivity

A set of sensitivities was performed which assumed DEC, DEP-E, and DEP-W were dispatched together and all reserves were calculated as a single company across the three regions. In these scenarios, all resources down to the firm load shed point can be utilized to assist each other and there is a priority in assisting each other before assisting an outside neighbor. The following three scenarios were simulated for the Combined Case and their results are listed in the table below:

1) Combined-Base

2) Combined Target 1,500 MW Import Limit - This scenario assumed a maximum import limit from external regions into the sister utilities of 1,500 MW[31].

3) Combined-Remove LFE

As shown in the table below, the combined target scenario yielded a 0.1 LOLE reserve margin of 16.75% (based on DEP and DEC coincident peak).

Table 26. Combined Case Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**weighted avg (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Combined Target	16.75%	17.00%	17.75%
Combined Target 1,500 MW Import Limit	18.00%	17.25%	18.25%
Combined Target - Remove LFE	17.25%	17.00%	18.25%

[31] 1,500 MW represents approximately 4.7% of the total reserve margin requirement which is still less constrained than the PJM and MISO assumptions noted earlier.

X. Conclusions

Based on the physical reliability results of the Island, Base Case, Combined Case, additional sensitivities, as well as the results of the separate DEC Study, Astrapé recommends that DEP continue to maintain a minimum 17% reserve margin for IRP purposes. This reserve margin ensures reasonable reliability for customers. Astrapé recognizes that a standalone DEP utility would require a 25.5% reserve margin to meet the one day in 10-year standard (LOLE of 0.1) and even with market assistance, DEP would need to maintain a 19.25% reserve margin. Customers expect electricity during extreme hot and cold weather conditions and maintaining a 17% reserve margin is estimated to provide an LOLE of 0.12 events per year which is slightly less reliable than the one day in 10-year standard (LOLE of 0.1). However, given the combined DEC and DEP sensitivity resulting in a 16.75% reserve margin, and the 16% reserve margin required by DEC to meet the one day in 10-year standard (LOLE of 0.1), Astrapé believes the 17% reserve margin as a minimum target is still reasonable for planning purposes. Since the sensitivity results removing all economic load forecast uncertainty increases the reserve margin to meet the 1 day in 10-year standard, Astrapé believes this 17% minimum reserve margin should be used in the short- and long-term planning process.

To be clear, even with 17% reserves, this does not mean that DEP will never be forced to shed firm load during extreme conditions as DEP and its neighbors shift to reliance on intermittent and energy limited resources such as storage and demand response. DEP has had several events in the past few years where actual operating reserves were close to being exhausted even with higher than 17% planning reserve margins. But if not for non-firm external assistance which this study considers, firm load would have been shed. In addition, incorporation of tail end reliability risk in modeling should be from statistically and historically defendable methods; not from including subjective risks that cannot be assigned probability. Astrapé's approach has been to model the system's risks around weather, load, generator performance, and market assistance as accurately as possible without overly conservative assumptions. Based on all results, Astrapé believes planning to a 17% reserve margin is prudent from a physical reliability perspective and for small increases in costs above the risk-neutral 10.25% reserve margin level, customers will experience enhanced reliability and less rate volatility.

As the DEP resource portfolio changes with the addition of more intermittent resources and energy limited resources, the 17% minimum reserve margin is sufficient as long as the Company has accounted for the capacity value of solar and battery resources which changes as a function of penetration. DEP should also monitor changes in the IRPs of neighboring utilities and the potential impact on market assistance. Unless DEP observes seasonal risk shifting back to summer, the 17% reserve margin should be reasonable but should be re-evaluated as appropriate in future IRPs and future reliability studies. To ensure summer reliability is maintained, Astrapé recommends not allowing the summer reserve margin to drop below 15%.[32]

[32] Currently, if a winter target is maintained at 17%, summer reserves will be above 15%.

XI. Appendix A

Table A.1 Base Case Assumptions and Sensitivities

Assumption	Base Case Value	Sensitivity	Comments
Weather Years	1980-2018		Based on the historical data, the 1980 - 2018 period aligns well with the last 100 years. Shorter time periods do not capture the distribution of extreme days seen in history.
Synthetic Loads and Load Shapes	As Documented in 2-21-20 Presentation	Impact of Climate Change on synthetic load shapes and peak load forecast	Note: This is a rather complex sensitivity and the ability to capture the impact of climate change may be difficult. We would appreciate input and suggestions from other parties on developing an approach to capture the potential impacts of climate change on resource adequacy planning.
LFE	Use an asymmetrical distribution. Use full LFE impact in years 4 and beyond. Recognize reduced LFE impacts in years 1-3.	1,2,3,5 year ahead forecast error	
Unit Outages	As Documented in 2-21-20 Presentation		
Cold Weather Outages	Moderate Cold Weather Outages: Capture Incremental Outages at temps less than 10 degrees based on the 2016 - 2018 dataset (~400 MW total across the DEC and DEP for all temperature below 10 degree. This will be applied on a peak load ratio basis) For Neighboring regions, the same ratio of cold weather outages to peak load will be applied.	2 Sensitivities: (1) Remove cold weather outages (2) Include cold weather outages based on 2014 -2018 dataset	The DEC and DEP historical data shows that during extreme cold temperatures it is likely to experience an increase in generator forced outages; this is consistent with NERC's research across the industry. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20WRA%202019_2020.pdf - page 5 https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf - beginning on pg 43
Hydro/Pumped Storage	As Documented in 2-21-20 Presentation		
Solar	As Documented in 2-21-20 Presentation		
Demand Response	As Documented in 2-21-20 Presentation	Sensitivity increasing winter DR	
Neighbor Assistance	As Documented in 2-21-20 Presentation	Island Sensitivity	Provide summary of market assistance during EUE hours; transmission versus capacity limited.
Operating Reserves	As Documented in 2-21-20 Presentation		
CT costs/ORDC/VOLL	As Documented in 2-21-20 Presentation	Low and High Sensitivities for each	
Study Topology	Determine separate DEC and DEP reserve margin targets	Combined DEC/DEP target	A simulation will be performed which assumes DEC, DEP-E and DEP-W are dispatched together and reserves are calculated as a single company across the three regions.

XII. Appendix B

Table B.1 Percentage of Loss of Load by Month and Hour of Day for the Base Case

	Month											
Hour of Day	1	2	3	4	5	6	7	8	9	10	11	12
1	-	-	-	-	-	-	-	-	-	-	-	-
2	0.12%	-	-	-	-	-	-	-	-	-	-	-
3	0.58%	0.12%	0.12%	-	-	-	-	-	-	-	-	-
4	1.84%	0.46%	0.12%	-	-	-	-	-	-	-	-	0.12%
5	5.30%	3.80%	0.12%	-	-	-	-	-	-	-	-	0.35%
6	10.71%	6.45%	-	-	-	-	-	-	-	-	-	0.92%
7	16.82%	10.71%	-	-	-	-	-	-	-	-	-	1.84%
8	21.89%	9.22%	-	-	-	-	-	-	-	-	-	1.61%
9	4.03%	0.46%	-	-	-	-	-	-	-	-	-	-
10	0.35%	-	-	-	-	-	-	-	-	-	-	-
11	0.46%	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	0.12%	-	-	-	-	-	-	-	-	-	-	-
14	0.12%	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-
17	0.12%	-	-	-	-	-	0.12%	-	-	-	-	-
18	0.12%	-	-	-	-	-	-	-	-	-	-	-
19	0.12%	-	-	-	-	-	-	-	-	-	-	-
20	0.12%	0.12%	-	-	-	-	-	-	-	-	-	-
21	-	0.12%	-	-	-	-	-	-	-	-	-	-
22	0.12%	0.12%	-	-	-	-	-	-	-	-	-	-
23	0.23%	-	-	-	-	-	-	-	-	-	-	-
24	0.00%	-	-	-	-	-	-	-	-	-	-	-
Sum	63.13%	31.57%	0.35%	-	-	-	0.12%	-	-	-	-	4.84%

ASTRAPÉ CONSULTING
innovation in electric system planning

Duke Energy Carolinas and Duke Energy Progress Storage Effective Load Carrying Capability (ELCC) Study

9/1/2020

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I. Summary of Methodology and Results

This study was requested by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) to analyze the capacity value of battery technology within each system. Capacity value is the reliability contribution of a generating resource and is the fraction of the rated capacity considered to be firm. This value is used for reserve margin calculation purposes. Because battery systems have limited energy storage capability and must be recharged, either from the grid or a dedicated generation resource, a battery's ability to reliably provide MW capacity when it is needed will differ from that of a fully dispatchable resource such as a gas-fired turbine, which can be called upon in any hour to produce energy, notwithstanding unit outages. Imperfect foresight of factors such as generator outages, load, and renewable energy generation leads to suboptimal battery charge and discharge scheduling, which can further impact the capacity contribution of energy storage resources. This study addresses the effects of both stored energy limits and imperfect foresight on the capacity value of battery energy storage systems. The study results provide the capacity value for battery energy storage systems used in the DEC and DEP Integrated Resource Plans.

Both DEC and DEP experience the majority of reliability risks in the winter, and battery energy storage systems are well-suited, up to certain penetration levels, to provide energy during the short peaks seen on cold winter mornings. This study analyzes the capacity contribution of 2-hour, 4-hour, and 6-hour stand-alone energy storage projects, and of paired battery plus solar systems, at several levels of market penetration by batteries, and two different levels of market penetration by solar for each utility. As market penetration increases, the system's net load peaks are flattened.

This lowers the capacity value of incremental energy storage as battery systems must discharge for longer periods to serve the wider net load peak.

A. Methodology

Astrapé performed this Effective Load Carrying Capacity (ELCC) study using the Strategic Energy Risk Valuation Model (SERVM) which is the same model used for the DEC and DEP 2020 Resource Adequacy Studies. The underlying load and resource modeling are documented in the Resource Adequacy Reports. Additional details of the model setup and assumptions are included in the Technical Modeling Appendix of this report.

The Effective Load Carrying Capacity (ELCC) methodology was used to calculate the capacity value of energy storage resources. A "base" case of the system is first established which involves calibrating DEC and DEP to the 1 day in 10-year industry standard of 0.1 Loss of Load Expectation (LOLE). This is a common industry standard as documented in the Resource Adequacy Reports and ensures that battery capacity is being valued within a reliable system. It is expected that battery energy storage would not perform well as a capacity resource in a system with LOLE much greater than 0.1, because periods in which firm load shed occurs would be longer in duration. Once the "base" case is established, the battery energy storage resources are added to the system. The additional resources improve LOLE to less than 0.1. Next, load is increased by adding a perfectly negative resource[1], until the LOLE is returned to 0.1 days per year[2]. The ratio of the additional

[1] Within the modeling, a perfectly negative unit is added to the system which is a unit that produces the same negative output in every hour of the year. This is equivalent to adding load in every hour of the year.
[2] Because it is difficult to return cases back to exactly 0.1 days per year, several load levels were analyzed for each battery setup and interpolation was performed to estimate the amount of load added to return to the Base Case LOLE.

load MW to the battery MW is the reliability contribution or capacity value of the battery resource. For example, if 100 MW of battery is added and achieves the same Base Case LOLE after adding 90 MW of load, the capacity value is 90 MW divided by 100 MW which equals 90%.

B. Study Scope

Astrapé calculated the average capacity value of battery energy storage systems with three different storage durations and at four levels of cumulative battery capacity for each utility (DEP and DEC). Tables 1 and 2 below show the different combinations of cumulative battery capacity and energy storage duration modeled for each utility. In addition, each capacity/duration combination was simulated with base and high total solar capacity assumption as indicated in the table headings.

Table 1. DEP Run Matrix (Base Solar = 4,000; High Solar = 5,500 MW)

	Standalone Battery Duration (hrs)		
Duration / Cumulative Battery Capacity	2	4	6
800 MW			
1,600 MW (incr 800)			
2,400 MW (incr 800)			
3,200 MW (incr 800)			

Table 2. DEC Run Matrix (Base Solar = 2,700; High Solar = 4,500 MW)

	Standalone Battery Duration (hrs)		
Duration / Cumulative Battery Capacity	2	4	6
400 MW			
800 MW (incr 400)			
1,200 MW (incr 400)			
1,600 MW (incr 400)			

Combined storage plus solar projects were also analyzed. Capacity contributions for 500 MW and 1,000 MW solar projects were analyzed for DEC, and 800 MW and 1,600 MW for DEP. The maximum MW output of each combined solar plus storage system was capped at the project's AC solar capacity, which is common for solar plus storage resources. Three different battery-to-solar MW capacity ratios were modeled, and it was assumed that the battery could be charged only from the solar array, and not from the grid. The solar generation profiles used were based on single-axis tracking systems with 1.5 inverter loading ratios. The individual permutations are shown in Tables 3 and 4 below and were replicated for both 2-hour and 4-hour storage durations.

Table 3. DEP Storage Plus Solar Permutations

Project Max Capacity (MW)	Solar Capacity (MW)	Battery Capacity (MW/% of solar)	Existing Standalone Solar Capacity (MW)
800	800	80 (10%)	3,200
800	800	240 (30%)	3,200
800	800	400 (50%)	3,200
1,600	1,600	160 (10%)	3,900
1,600	1,600	480 (30%)	3,900
1,600	1,600	800 (50%)	3,900

Table 4. DEC Storage Plus Solar Permutations

Project Max Capacity (MW)	Solar Capacity (MW)	Battery Capacity (MW/% of solar)	Existing Standalone Solar Capacity (MW)
500	500	80 (10%)	2,200
500	500	240 (30%)	2,200
500	500	400 (50%)	2,200
1,000	1,000	160 (10%)	3,200
1,000	1,000	480 (30%)	3,200
1,000	1,000	800 (50%)	3,200

C. Battery Modeling

For this study, battery resources were modeled in three operating modes using SERVM. We describe these as (1) Preserve Reliability Mode (2) Economic Arbitrage Mode and (3) Fixed Dispatch Mode based on a set rate schedule.

The objective of Preserve Reliability Mode is to provide energy only during reliability events. In this mode, SERVM maintains full charge on the storage resource at all times and only dispatches the resource during these reliability events. This mode allows the battery to run a small number of days per year but provides a high degree of reliability. This option assumes that the utility has full control of the battery and that it would be used in the most conservative way possible. While this method would provide the most capacity value, it provides little to no economic value and is not how batteries are typically expected to be run on the system. For this reason, Preserve Reliability Mode is largely an academic exercise that provides a theoretical maximum capacity value but is not directly useful for planning purposes.

The objective of Economic Arbitrage Mode is to maximize the economic value of the battery. In this mode, SERVM schedules the battery to charge at times when system energy costs are low, and to discharge when system energy costs are high. Generally, this type of dispatch aligns well with resource adequacy risks, meaning the battery will be available to discharge during peak net load conditions when loss of load events are most likely to occur. In this mode, SERVM offers recourse options during a reliability event. In other words, SERVM allows the schedule of the battery to be adjusted in real time, and discharge if its state of charge is greater than zero to avoid firm load shed. This method also assumes the utility has full control of the battery and best represents how stand-alone batteries are expected to be operated.

Operation in Fixed Dispatch Mode assumes that the utility has no control over battery operations and that the battery owner simply charges and discharges to maximize net revenue based on a set rate schedule. A battery operating in this mode provides much less capacity value than a battery controlled by the utility. It is not anticipated that stand-alone batteries would be operated in this mode, but Fixed Dispatch is an appropriate assumption for solar plus storage projects that are subject to Public Utility Regulatory Policies Act (PURPA) avoided cost contracts and rates. The study results show that the capacity value of batteries operated in Fixed Dispatch Mode declines significantly over time if the rate structure remains fixed, because loss of load hours will shift out of alignment with the hours in which the rate structure incentivizes battery discharging as the system evolves.

For all three modes, batteries were assumed to have no limits on ramping capability or constraints on number of cycles per day outside of the ability to charge the battery. Capacity values were calculated for stand-alone batteries under all three modes described above. Astrapé recommends capacity values used in the IRPs to reflect the results for Economic Arbitrage Mode for stand-alone batteries and for solar plus storage projects over which the utility has full dispatch rights. For solar plus storage projects subject to PURPA rates, Astrapé recommends that IRP capacity values reflect the results for Fixed Dispatch Mode.

D. Imperfect Foresight for Unit Commitment

SERVM does not have perfect day-ahead foresight around generator outages, load, and solar generation as it commits and dispatches resources. This imperfect knowledge does not impact the commitment and dispatch of batteries modeled under the Preserve Reliability Mode or Fixed Dispatch Mode. However, these uncertainties do impact batteries modeled in Economic Arbitrage Mode because SERVM is scheduling to minimize production costs, and day-ahead schedules will be sub-optimal to the extent that day-ahead forecasts do not perfectly match real time conditions. The day ahead solar and load uncertainty distributions are included in the Technical Appendix. Generator forced outages used in this study are the same as those used in the 2020 Resource Adequacy Study. The impact of these forecast uncertainties on the capacity value of batteries in Economic Arbitrage Mode can be estimated by comparing the difference between the capacity value of batteries in this mode and that of batteries in Preserve Reliability Mode, which maximizes capacity value at the expense of economic value.

E. Stand Alone Battery Results

Tables 5 and 6 shows the average capacity value results for stand-alone batteries in DEP up to cumulative system battery capacity of 3,200 MW, assuming two different levels of cumulative solar capacity. As discussed above, the capacity value for batteries in Preserve Reliability Mode is approximately 5-10% greater than that of batteries in Economic Arbitrage Mode. This is due to the fact that the Economic Arbitrage Mode schedules the resource day ahead to flatten the net load shape. As load, solar generation, or generator availability changes, the hours in which the resource may be needed for a reliability event could change as well, reducing the reliability of the battery resource to the extent that state of charge is misaligned with the new reliability event hours. If the battery is forced to follow a fixed dispatch schedule with no ability to respond during reliability events, the capacity value is substantially lower. This effect, combined with the fact that battery capacity values decline as cumulative battery capacity increases, indicates that it is imperative for the utility to have control of these resources as battery penetrations increase. Although as stated previously, stand-alone batteries are not expected to operate in Fixed Dispatch Mode, and it is likely that rate structures would be adjusted as cumulative battery capacity increased so as to maintain alignment between fixed dispatch scheduling and resource adequacy needs. Because of this, it is expected that the capacity values in the higher battery penetration cases with fixed dispatch are unreasonably low.

Table 5. DEP Standalone Capacity Value Results

			Full control and reserved for LOLE events (Academic Only)	Full control, dispatched for economic arbitrage - allowed to change dispatch during reliability events (Recommended)	No control, dispatch based on rate schedule; no change in dispatch during reliability events (Academic Only)
Solar Capacity (MW)	**Duration (hr)**	**Battery Capacity (MW)**	**Average Capacity Value - Preserve Reliability**	**Average Capacity Value - Economic Arbitrage**	**Average Capacity Value -Fixed Schedule**
4,000	2	800	95%	88%	55%
4,000	4	800	97%	94%	62%
4,000	6	800	97%	95%	62%
4,000	2	1,600	77%	66%	37%
4,000	4	1,600	93%	87%	40%
4,000	6	1,600	95%	90%	40%
4,000	2	2,400	65%	57%	27%
4,000	4	2,400	86%	78%	27%
4,000	6	2,400	92%	84%	28%
4,000	2	3,200	56%	50%	22%
4,000	4	3,200	76%	69%	22%
4,000	6	3,200	86%	78%	23%
5,500	2	800	96%	90%	60%
5,500	4	800	100%	97%	69%
5,500	6	800	100%	98%	75%
5,500	2	1,600	80%	72%	39%
5,500	4	1,600	94%	88%	41%
5,500	6	1,600	97%	93%	41%
5,500	2	2,400	68%	60%	29%
5,500	4	2,400	86%	80%	29%
5,500	6	2,400	94%	87%	28%
5,500	2	3,200	57%	52%	21%
5,500	4	3,200	80%	72%	21%
5,500	6	3,200	89%	82%	21%

The DEC results for stand-alone batteries are shown in the following table.

Table 6. DEC Standalone Capacity Value Results

			Full control and reserved for LOLE events (Academic Only)	Full control, dispatched for economic arbitrage - allowed to change dispatch during reliability events (Recommended)	No control, dispatch based on rate schedule; no change in dispatch during reliability events (Academic Only)
Solar Capacity (MW)	Duration (hr)	Battery Capacity (MW)	Average Capacity Value - Preserve Reliability	Average Capacity Value - Economic Arbitrage	Average Capacity Value -Fixed Schedule
2,700	2	400	91%	85%	74%
2,700	4	400	98%	92%	80%
2,700	6	400	100%	100%	82%
2,700	2	800	88%	75%	59%
2,700	4	800	96%	91%	66%
2,700	6	800	96%	93%	79%
2,700	2	1,200	74%	64%	48%
2,700	4	1,200	94%	84%	56%
2,700	6	1,200	95%	90%	73%
2,700	2	1,600	65%	57%	39%
2,700	4	1,600	88%	80%	41%
2,700	6	1,600	95%	89%	57%
4,500	2	400	96%	90%	74%
4,500	4	400	100%	100%	80%
4,500	6	400	100%	100%	83%
4,500	2	800	92%	81%	62%
4,500	4	800	97%	90%	69%
4,500	6	800	97%	93%	79%
4,500	2	1,200	81%	66%	53%
4,500	4	1,200	94%	87%	58%
4,500	6	1,200	95%	93%	75%
4,500	2	1,600	73%	65%	42%
4,500	4	1,600	92%	86%	45%
4,500	6	1,600	94%	91%	61%

F. Sensitivity – 6-Hour Standalone Battery at Higher Market Penetration Levels

Finally, sensitivity analysis was performed on stand-alone battery capacity to assess the effect of adding additional battery capacity above the 1,600 MW for DEC and 3,200 MW for DEP 4-hour configurations. Two 800 MW blocks of 6-hour battery capacity were added to DEP, and two 400 MW blocks of 6-hour battery capacity were added to DEC. The results in Tables 7 and 8 show that despite the additional storage having 6-hour duration, the overall average capacity value for storage still declines.

Table 7. DEP Sensitivity Results

DEP	Battery Penetration	Capacity Value - Economic Arbitrage
all 4-hour	800	97%
all 4-hour	1,600	88%
all 4-hour	2,400	80%
all 4-hour	3,200	72%
additional 6-hour	4,000	67%
additional 6-hour	4,800	63%

Table 8. DEC Sensitivity Results

DEC	Battery Penetration	Capacity Value - Economic Arbitrage
all 4-hour	400	100%
all 4-hour	800	90%
all 4-hour	1,200	87%
all 4-hour	1,600	86%
additional 6-hour	2,000	82%
additional 6-hour	2,400	79%

G. Combined Solar Plus Storage Battery Results

The combined solar plus storage results are shown in Table 9 and 10 below. For these runs, only the Economic Arbitrage Mode and the Fixed Schedule Mode analyses were conducted. The capacity values are shown as a percentage of the MW capacity of the paired solar project. Because solar capacity value in the winter is minimal, it is likely that the battery contributes most of the value shown for the combined solar plus storage system. Solar provides slightly more value in DEC, where there is a very small amount of summer LOLE that corresponds well to solar generation. Because the penetration of battery capacity wasn't increased as high as the standalone battery analysis, the battery capacity remained high. It is expected that battery capacity value would decline as cumulative installed battery capacity, whether coupled with solar or charged solely from the grid, increased further, as indicated by the standalone battery analysis.

Table 9. DEP Solar Plus Storage Results

Standalone Solar Capacity (MW)	Duration (hr)	Project Max Capacity (MW)	Battery Capacity (MW / % of Solar)	Solar Capacity Paired with Storage (MW)	Economic Arbitrage - Utility Controlled Average Capacity Value (% of Project Max Capacity)	No Dispatch Rights - Fixed Schedule Average Capacity Value (% of Project Max Capacity)
3,200	2	800	80 (10%)	800	12%	8%
3,200	2	800	240 (30%)	800	31%	21%
3,200	2	800	400 (50%)	800	45%	25%
3,200	4	800	80 (10%)	800	12%	11%
3,200	4	800	240 (30%)	800	31%	27%
3,200	4	800	400 (50%)	800	49%	34%
3,900	2	1,600	160 (10%)	1,600	12%	8%
3,900	2	1,600	480 (30%)	1,600	30%	17%
3,900	2	1,600	800 (50%)	1,600	46%	23%

3,900	4	1,600	160 (10%)	1,600	12%	11%
3,900	4	1,600	480 (30%)	1,600	31%	23%
3,900	4	1,600	800 (50%)	1,600	51%	27%

Table 10. DEC Solar Plus Storage Results

Standalone Solar Capacity (MW)	Duration (hr)	Project Max Capacity (MW)	Battery Capacity (MW / % of Solar)	Solar Capacity Paired with Storage (MW)	Economic Arbitrage - Utility Controlled Average Capacity Value (% of Project Max Capacity)	No Dispatch Rights - Fixed Schedule Average Capacity Value (% of Project Max Capacity)
2,200	2	500	50 (10%)	500	11%	8%
2,200	2	500	150 (30%)	500	28%	20%
2,200	2	500	250 (50%)	500	43%	28%
2,200	4	500	50 (10%)	500	14%	14%
2,200	4	500	150 (30%)	500	30%	28%
2,200	4	500	250 (50%)	500	44%	43%
3,200	2	1,000	100 (10%)	1,000	9%	7%
3,200	2	1,000	300 (30%)	1,000	26%	19%
3,200	2	1,000	500 (50%)	1,000	41%	30%
3,200	4	1,000	100 (10%)	1,000	10%	9%
3,200	4	1,000	300 (30%)	1,000	28%	25%
3,200	4	1,000	500 (50%)	1,000	43%	41%

To further illustrate the potential misalignment between a fixed dispatch schedule and Expected Unserved Energy (EUE) hours, Figures 1 and 2 below show the solar plus storage profiles for January of systems operating according to a fixed dispatch schedule (primary axis) with the EUE hours (secondary axis). The fixed dispatch schedule aligns better with the EUE hours for DEC than for DEP, resulting in a higher capacity value for these systems in DEC. The misalignment shown in both charts would be expected to increase over time if rate schedules were not adjusted, as battery storage is added to the system or other factors change.

Figure 1. DEP Fixed Dispatch for Combined Cases

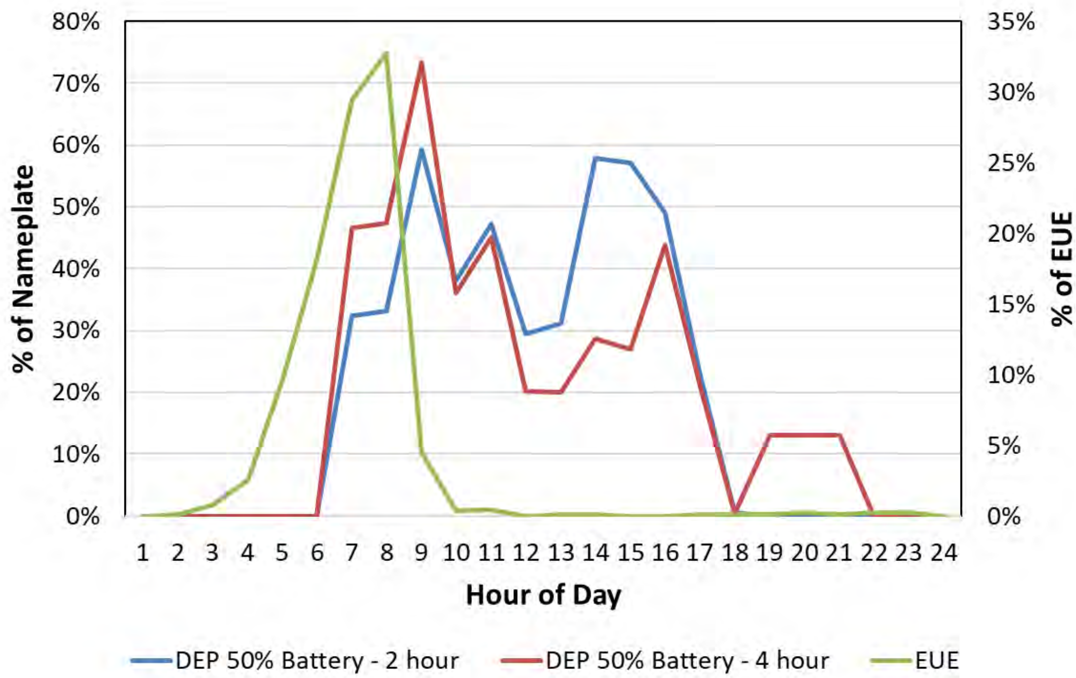
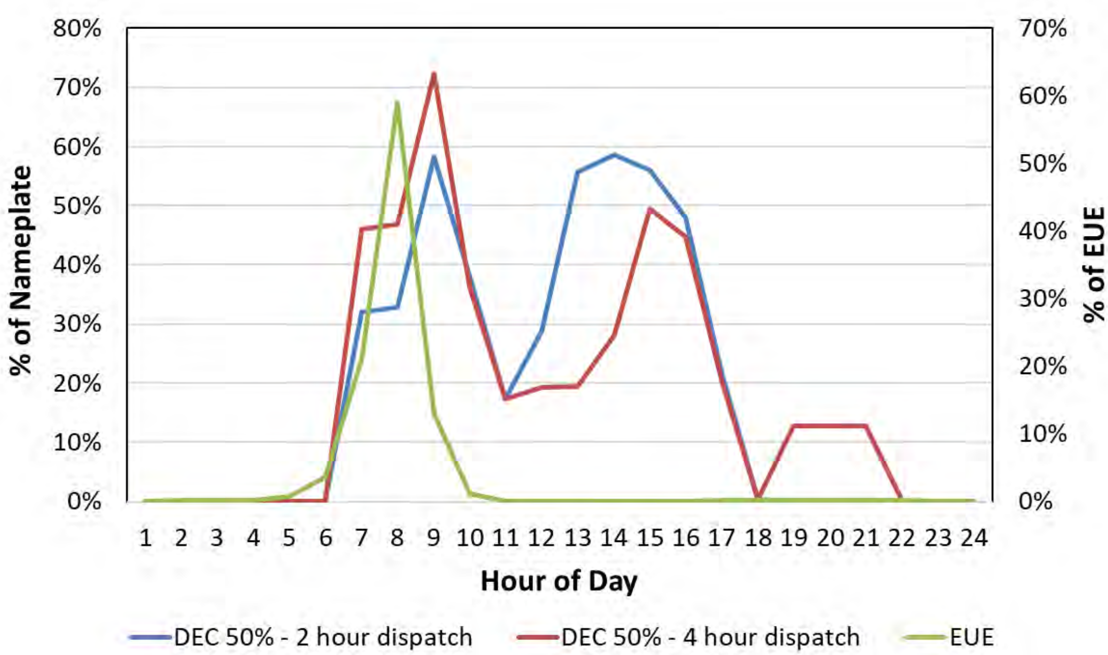


Figure 2. DEC Fixed Dispatch for Combined Cases



H. Conclusions

The results of the ELCC Study estimate significant capacity value, that reduces as penetration increases, for 4-hour and 6-hour storage for both Companies to assist in offsetting the winter reliability risks. In DEP, 2,400 MW of 4-hour storage is estimated to have an average capacity value of 80%. In DEC, 1,600 MW of 4 – hour storage is estimated to have an average capacity value of greater than 85%. The study reveals significant capacity value in scenarios where the utility had dispatch rights over the storage compared to the owner discharging or charging based only on an economic rate schedule. The combined solar plus storage projects, including those with a battery to solar ratio of 50%, showed capacity values commensurate with the battery size. While this study does include some level of operator uncertainty due to day-ahead dispatch of storage, there are potentially additional operational constraints of storage technology that were not explored in this study. For example, there were no charging/discharging constraints, ramping constraints, daily cycle constraints, or degradation assumed in this Study. As the Companies and industry gain experience about the large-scale deployment of storage, these estimates should be revisited.

II. Technical Modeling Appendix

The following sections include a discussion on the setup and assumptions used to evaluate the capacity value of battery. The Study utilized the load and resource assumptions from the 2020 Resource Adequacy Study and Framework which are detailed in Sections III and IV of those reports.[3]

A. SERVM Framework and Cases

The study uses the same 2024 study year framework as the Base Case 2020 Resource Adequacy Study and includes 39 weather years (1980 – 2018), five load forecast error multipliers, and Monte Carlo generator outages. For capacity value studies in which significant levels of cumulative battery capacity are analyzed, the number of iterations and run times are extensive. For example, each of the weather year and load forecast error multipliers was simulated with 100 generator outage iterations. Two measures were taken to reduce the number of iterations and the simulation time.

First, since the capacity value is calculated from only cases that contain LOLE, weather years with zero LOLE were removed from the analysis. This trimmed down the simulations from 39 years to 24 years. Each weather year was still given a 1/39 chance of occurring. Second, instead of modeling all external neighbors, an hourly purchase resource was developed based on the Base Case reserve margin study which allowed external neighbors to be eliminated from the modeling

[3] Duke Energy Carolinas 2020 Resource Adequacy Study
Duke Energy Progress 2020 Resource Adequacy Study

to significantly reduce run time. To develop the market purchase resource, hourly purchase reports from the Base Case were used and the relationship between net load and purchases was estimated by hour of day and month. This relationship expressing purchases as a function of net load was then applied to all the weather years in the modeling. Because the Base Case simulations target 0.1 LOLE, this assumption is reasonable and was used for all the incremental battery simulations. With these two changes, the run times were reduced significantly. Each level of battery was studied with 24 weather years, five load forecast error multipliers, and 100 iterations of generator outage draws.

B. Load and Solar Uncertainty

Historical hourly load and solar generation were compared to day-ahead forecasts to determine day ahead forecast uncertainty. The following tables show the data that was used. The first column of values displays the forecast error and the columns to the right show probabilities of the forecast error occurring. As one would expect, the day ahead forecast for load was fairly low while the solar error was much higher. As discussed in the summary, SERVM draws from this set of forecast error to develop day ahead net load forecasts to commit and dispatch units. Then in real time the actual net load is realized, and the fleet must adjust to meet net load.

Table 11. DEP Day Ahead Load Uncertainty

		DEP Normalized Load						
		30%-40%	40%-50%	50%-60%	60%-70%	70%-80%	80%-90%	90%-100%
Over- Forecast (Negative is Under-Forecast) in Normalized Load	-20%	0%	0%	0%	0%	0%	0%	0%
	-18%	0%	0%	0%	0%	0%	0%	0%
	-16%	0%	0%	0%	0%	0%	0%	0%
	-14%	0%	0%	0%	0%	0%	0%	0%
	-12%	0%	0%	0%	0%	0%	0%	0%
	-10%	0%	0%	1%	1%	0%	0%	0%
	-8%	0%	0%	1%	2%	2%	1%	0%
	-6%	1%	2%	4%	6%	6%	4%	0%
	-4%	6%	11%	14%	16%	15%	17%	3%
	-2%	53%	40%	32%	28%	28%	24%	9%
	0%	36%	38%	34%	26%	25%	24%	32%
	2%	4%	7%	12%	14%	12%	13%	32%
	4%	0%	1%	3%	6%	8%	7%	14%
	6%	0%	0%	0%	1%	3%	7%	8%
	8%	0%	0%	0%	0%	1%	1%	1%
	10%	0%	0%	0%	0%	0%	1%	1%
	12%	0%	0%	0%	0%	0%	1%	0%
	14%	0%	0%	0%	0%	0%	0%	0%
	16%	0%	0%	0%	0%	0%	0%	0%
	18%	0%	0%	0%	0%	0%	0%	0%
	20%	0%	0%	0%	0%	0%	0%	0%

Table 12. DEC Day Ahead Load Uncertainty

		DEC Normalized Load						
		30%-40%	40%-50%	50%-60%	60%-70%	70%-80%	80%-90%	90%-100%
Over- Forecast (Negative is Under-Forecast) in Normalized Load	-20%	0%	0%	0%	0%	0%	0%	0%
	-18%	0%	0%	0%	0%	0%	0%	0%
	-16%	0%	0%	0%	0%	0%	0%	0%
	-14%	0%	0%	0%	0%	0%	0%	0%
	-12%	0%	0%	0%	0%	0%	0%	0%
	-10%	0%	0%	0%	0%	0%	0%	0%
	-8%	0%	0%	0%	1%	1%	0%	0%
	-6%	0%	1%	2%	2%	3%	3%	0%
	-4%	5%	6%	8%	13%	16%	14%	3%
	-2%	56%	37%	31%	30%	24%	26%	9%
	0%	40%	49%	44%	30%	30%	25%	38%
	2%	0%	6%	12%	16%	14%	12%	16%
	4%	0%	0%	2%	6%	7%	9%	12%
	6%	0%	0%	0%	2%	4%	4%	7%
	8%	0%	0%	0%	0%	1%	5%	5%
	10%	0%	0%	0%	0%	0%	2%	5%
	12%	0%	0%	0%	0%	0%	0%	6%
	14%	0%	0%	0%	0%	0%	0%	0%
	16%	0%	0%	0%	0%	0%	0%	0%
	18%	0%	0%	0%	0%	0%	0%	0%
	20%	0%	0%	0%	0%	0%	0%	0%

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Table 13. DEP Day Ahead Solar Uncertainty

		Normalized Solar									
		0%-10%	10%-20%	20%-30%	30%-40%	40%-50%	50%-60%	60%-70%	70%-80%	80%-90%	90%-100%
Over- Forecast (Negative is Under-Forecast) in Normalized Solar Output	-60%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	-55%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	-50%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%
	-45%	0%	0%	1%	3%	1%	1%	0%	0%	0%	0%
	-40%	0%	0%	1%	3%	5%	2%	0%	0%	0%	0%
	-35%	0%	1%	2%	4%	9%	6%	1%	0%	0%	0%
	-30%	0%	0%	6%	9%	12%	9%	8%	0%	0%	0%
	-25%	0%	1%	8%	10%	17%	15%	17%	4%	0%	0%
	-20%	0%	4%	9%	12%	17%	16%	23%	21%	1%	0%
	-15%	0%	13%	14%	14%	14%	18%	25%	36%	38%	0%
	-10%	1%	15%	16%	11%	11%	17%	13%	25%	42%	20%
	-5%	68%	23%	13%	15%	5%	9%	7%	9%	9%	59%
	0%	30%	25%	14%	8%	4%	3%	4%	2%	6%	20%
	5%	1%	14%	8%	5%	2%	2%	1%	1%	2%	0%
	10%	0%	3%	7%	2%	1%	2%	0%	1%	1%	2%
	15%	0%	0%	2%	2%	1%	0%	1%	0%	1%	0%
	20%	0%	0%	0%	1%	0%	1%	0%	0%	0%	0%
	25%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	30%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	35%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	40%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Table 14. DEC Day Ahead Solar Uncertainty

		Normalized Solar									
		0%-10%	10%-20%	20%-30%	30%-40%	40%-50%	50%-60%	60%-70%	70%-80%	80%-90%	90%-100%
Over- Forecast (Negative is Under-Forecast) in Normalized Solar Output	-50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	-45%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%
	-40%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%
	-35%	0%	0%	1%	2%	2%	2%	2%	0%	0%	0%
	-30%	0%	0%	1%	3%	3%	5%	3%	1%	0%	0%
	-25%	0%	2%	4%	5%	4%	7%	6%	2%	0%	0%
	-20%	0%	3%	7%	10%	7%	9%	9%	6%	3%	0%
	-15%	0%	8%	9%	13%	9%	10%	16%	18%	16%	0%
	-10%	1%	9%	16%	13%	20%	11%	17%	23%	18%	5%
	-5%	35%	18%	13%	15%	22%	19%	14%	18%	14%	16%
	0%	63%	22%	14%	13%	12%	18%	14%	14%	19%	23%
	5%	1%	20%	11%	9%	10%	9%	10%	7%	16%	17%
	10%	0%	15%	13%	9%	6%	5%	5%	7%	8%	17%
	15%	0%	2%	9%	3%	2%	1%	2%	1%	3%	10%
	20%	0%	0%	1%	3%	1%	1%	2%	1%	1%	8%
	25%	0%	0%	0%	0%	2%	0%	0%	0%	0%	3%
	30%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%
	35%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	40%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	45%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

C. Stand Alone Battery Fixed Dispatch

Although the fixed dispatch analysis for a stand-alone battery is not used in the IRP, the fixed dispatch schedule based on North Carolinas Utilities Commission Docket No. E-100 Sub 158 ("Sub 158") avoided cost rates are shown below. The tables represent the dispatch of a 100 MW battery for 2, 4, and 6 hour durations.

Table 15. DEP Stand Alone Fixed Dispatch 2-Hour

2-Hour (MW)		Hour																							
Month	Calendar	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
2	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
3	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
4	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
1	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
2	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
3	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
4	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39

Table 16. DEP Stand Alone Fixed Dispatch 4-Hour & 6-Hour

4-Hour, 6-Hour (MW)		Hour																							
Month	Calendar	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Weekday	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
2	Weekday	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
3	Weekday	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
4	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekday	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
1	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
2	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
3	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
4	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59

Table 17. DEC Stand Alone Fixed Dispatch 2-Hour

2-Hour (MW)		Hour																							
Month	Calendar	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
2	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
3	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
4	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekday	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	0	0	0	0	0	50	50	50	50	0	0	0	-20
7	Weekday	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	0	0	0	0	0	50	50	50	50	0	0	0	-20
8	Weekday	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	0	0	0	0	0	50	50	50	50	0	0	0	-20
9	Weekday	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	0	0	0	0	0	50	50	50	50	0	0	0	-20
10	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
1	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
2	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
3	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
4	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Weekend	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	0	0	0	0	0	50	50	50	50	0	0	0	-20
8	Weekend	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	0	0	0	0	0	50	50	50	50	0	0	0	-20
9	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39

Table 18. DEC Stand Alone Fixed Dispatch 4-Hour

4-Hour (MW)		Hour																							
Month	Calendar	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Weekday	-78	-78	-78	-78	-78	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	50	100	100	100	50	0	-78
2	Weekday	-78	-78	-78	-78	-78	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	50	100	100	100	50	0	-78
3	Weekday	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
4	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekday	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
7	Weekday	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
8	Weekday	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
9	Weekday	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
10	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekday	-78	-78	-78	-78	-78	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	50	100	100	100	50	0	-78
1	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
2	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
3	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
4	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Weekend	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
8	Weekend	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
9	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59

Table 19. DEC Stand Alone Fixed Dispatch 6-Hour

6-Hour (MW)		Hour																							
Month	Calendar	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Weekday	-98	-98	-98	-98	-98	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	100	100	100	100	100	0	-98
2	Weekday	-98	-98	-98	-98	-98	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	100	100	100	100	100	0	-98
3	Weekday	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
4	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekday	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	0	33	33	33	33	100	100	100	100	33	33	0	-59
7	Weekday	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	0	33	33	33	33	100	100	100	100	33	33	0	-59
8	Weekday	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	0	33	33	33	33	100	100	100	100	33	33	0	-59
9	Weekday	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	0	33	33	33	33	100	100	100	100	33	33	0	-59
10	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekday	-98	-98	-98	-98	-98	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	100	100	100	100	100	0	-98
1	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
2	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
3	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
4	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Weekend	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
8	Weekend	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
9	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59

D. Combined Solar Plus Storage Fixed Dispatch

The fixed dispatch profiles for solar plus storage were provided by Duke Energy using internal dispatch optimization models. Figure 3 and Figure 4 show the average dispatch of these resources for January and July. Battery charging and discharging were optimized to capture clipped DC solar energy and to maximize revenue based on Sub 158 avoided cost rates. The models utilize "perfect foresight" of solar generation over 3-day periods. As stated in the summary, for combined solar plus storage projects that are subject to PURPA, Astrapé recommends these capacity values; however, for utility-controlled projects Astrapé recommends the capacity values using the Economic Arbitrage Mode.

Figure 3. DEP Combined Solar Plus Storage Fixed Dispatch

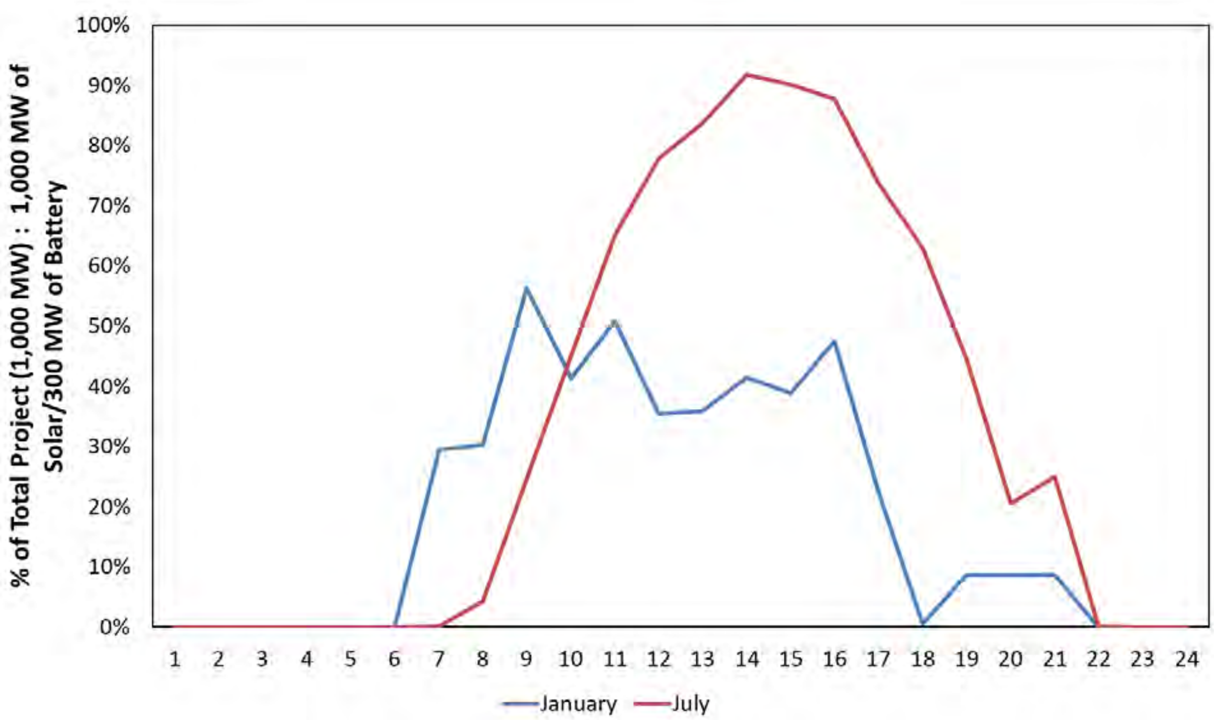
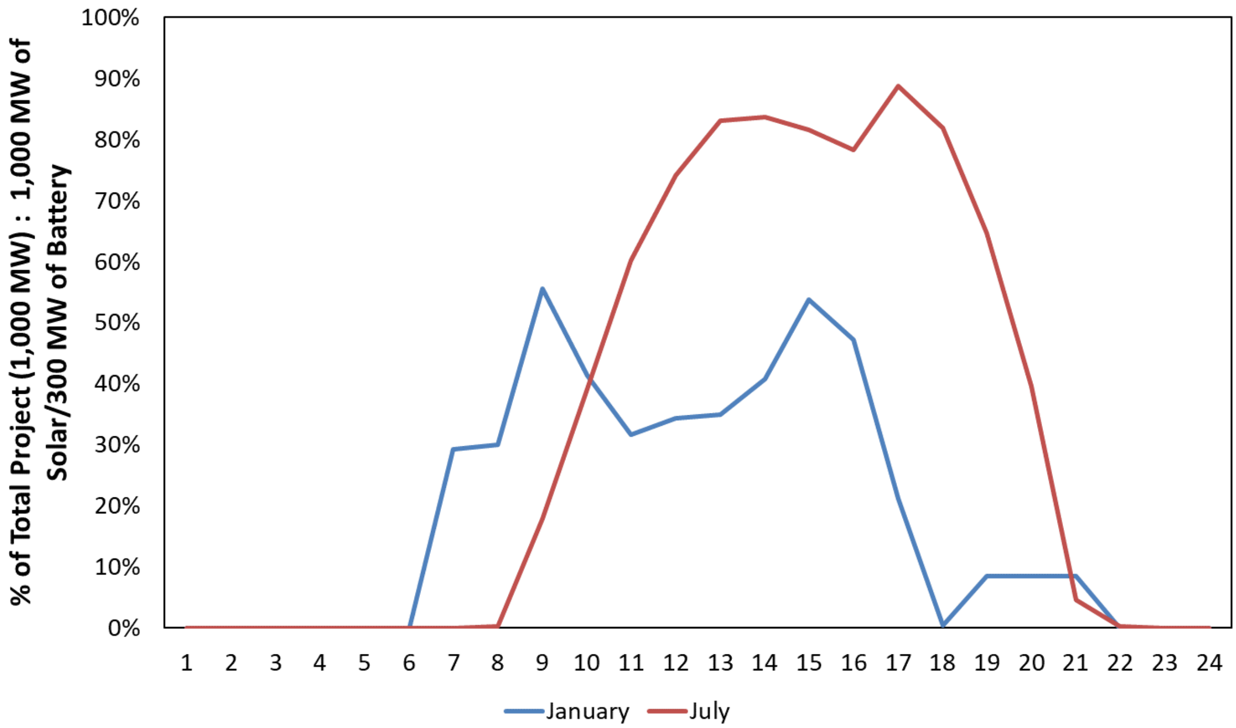


Figure 4. DEC Combined Solar Plus Storage Fixed Dispatch



E. Firm Load Shed Event

Loss of Load Expectation is defined as any day that has hourly firm load shed and is consistent with the Resource Adequacy Studies. A firm load shed event is defined as any day in which resources could not meet load, even after utilizing neighbor assistance and demand response programs, regardless of the number of hours affected. Regulating reserves of 218 MW in DEC and 150 MW in DEP were always maintained. Batteries were allowed to serve regulating reserves.